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Properly Defining "Green Electricity" is Key to India's Broader Energy Transition

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Properly Defining “Green Electricity” is Key to India’s Broader Energy Transition

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Executive Summary

- The lowest hanging fruit for decarbonisation is adding more wind and solar power, which are cost-competitive compared with other alternatives.

- In addition to globally leading targets to scale up wind and solar power, India has ambitious plans for using electricity for new services, including mobility (electric vehicles) and green hydrogen production for industrial use. Such use would happen even before India's electricity grid is carbon-free. Thus, a key question is how "green" will such services be.

- Making the grid greener has two challenges. The first challenge relates to scaling up wind and solar power. As wind and solar capacities increase, grid integration will become increasingly difficult because of the well-known challenge of renewable energy's (RE) intermittency, for which one solution would be to add storage. Unfortunately, storage is likely to be more expensive in the foreseeable future than many models and public documents estimate for two reasons. One, the upfront costs associated with grid-scale batteries are likely to be much higher than estimates often calculated based on the cost of cheaper automotive batteries. Two, most models fail to capture battery usage patterns or duty cycles and instead use an expected or ideal usage pattern. Such calculations typically assume almost full daily usage as part of calculating the levelised cost of energy (LCOE). Another option for increasing RE output is oversizing RE capacity with expected strategic (temporary) excess. This is cost-effective up to a point, but it also means India must add even more RE capacity.

- The second challenge with wind and solar power (without storage) is that their variability and performance in a portfolio of supply can significantly reduce the "greenness" of grid-based electricity powering electric vehicles (EVs) or the production of hydrogen. Pure matching of hydrogen production or EV charging *to times and locations* when there is *incremental green power* becomes expensive or limiting. Furthermore, instead of matching, current green energy and green hydrogen norms in India are based on average-basis accounting over a long period, termed banking. This means over- and under-generating RE at different times while still relying on traditional supplies, predominantly coal, for non-direct–RE periods. Systems based on banking can reduce the growth of carbon dioxide (CO_2) emissions through offsets—that too only in the short run—but cannot eliminate emissions.

- Policies and frameworks should be updated to ensure electricity services are truly green to the extent possible. This requires policies where granular *additionality* of green supply is the key criterion and is measured across a short timeframe and not just averaged over time. Such measurements need rigorous norms and scientific tools, such as grid models, for verifying and ease of developer planning.

- Proper frameworks are essential not just for reducing CO_2 emissions but also for compliance with green norms that may be set by other countries, banks, or third parties, which would thus impact exports or access to climate funding.

1. Introduction: A World of Rising Green Energy

The Kochi airport in Kerala has a large sign that proudly declares it is the "world's first 100% solar airport". You can see vast arrays of solar panels covering the airport grounds, including covering the parking lots and buffer space around the airport. But what you will not see, or find even if you tried, are batteries that would be required if the energy from these solar panels is to power the airport at night.

So, what does it mean to be 100% solar? Answering this question requires understanding the dynamics of electricity generation over the day and year and how energy accounting is typically done. It is also a key issue for India's energy transition.

The airport knows that it is not running directly on solar power all the time. It over-generates solar energy during the day compared to its consumption and feeds it into the grid through the utility. It then takes back power from the utility at night but accounts for such consumption as "solar power" because of the solar power exported during the day. This is not unusual, and many companies do the same. In Indian industry parlance, this is energy "banking", akin to what some literature calls "offsets."[1] It is understood that in the evening, especially until storage technologies mature, grid-supplied energy is unlikely to come from zero-carbon or green sources of power. For India, such power is likely to be generated mostly using coal.

The good news is the future will not look like the present—where coal dominates the electricity supply. But until the grid becomes greener, coal would remain India's mainstay, producing 71.87% of the country's grid electricity in FY2019–20.[2,3]

Driven by falling prices for wind and solar power and environmental concerns, India has set some of the most ambitious renewable energy (RE) targets in the world. It aims to increase RE capacity to approximately 450 GW by 2030, a significant subset of the 500 GW "non-fossil" capacity the prime minister pledged in Glasgow in November 2021 at the UN Climate Change Conference COP26. This was preceded by his September 2019 announcement at the United Nations Climate Action Summit in New York to establish 450 GW of RE. Such targets translate to a very high annual growth rate based on the early 2023 renewable capacity of over 165 GW—a metric that includes over 45 GW of traditional (large) hydropower as a renewable source of power.

There are more specific plans to establish 420 GW of wind and solar power by 2030, which would require an even higher growth rate. While China's absolute ambitions for RE growth are about four times higher,[4] these are for a grid about six times the size of India's. As an additional reference, the US presently has approximately 25 GW of solar capacity under construction (Kennedy, 2023). In contrast, India's grid has almost 40 GW of solar parks sanctioned and under various stages of development (PIB, 2022b), a figure that excludes rooftop solar. This is for a grid about one-third the size of the US grid.

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1 The term "offsets" in climate change has a range of meanings, e.g., when applied to greenhouse gases such as CO_2. In this paper, the focus is on the power sector alone. Banking as used in this paper applies to power being given to a discom and subsequently taken back at a different point in time (sometimes for a small fee). Banking is done through the utility while offsets can be against any entity willing to trade, often using renewable energy certificates (RECs).

2 This is the last year before significant COVID-19 distortions, which decreased coal power supply disproportionally, and the recovery in 2022–23 has been heavily coal-driven.

3 If captive power is added to the widely quoted figures for the grid (utility supply), coal generated 73.92% of India's electricity in FY2019–20 (based on data from CEA, 2021).

4 Observers note that the actual growth of RE in China is much higher than the slightly more conservative (but still high growth) official Chinese ambitions for RE capacity. Experts believe China will achieve its 2030 targets by 2025 or perhaps even earlier.

Numerous studies and ongoing discussions have flagged the challenges in scaling up RE supply. The challenges span issues relating to financing (Clean Energy Finance Forum, 2016), manufacturing (especially to reduce imports and supply chain risks) (IEA, 2022; Chadha & Sivamani, 2022), and grid integration (CEA, 2020; Tongia, Harish, & Walawalkar, 2018). These are all important issues, but this paper focuses on the problems of variability and usability of such green power, which is expected to power future electric vehicles and the production of green hydrogen, along with other uses.

This paper addresses the following key questions:

1) How variable are wind and solar power in India? What does this mean for their utilisation?
2) What are the possibilities for increasing the output and smoothening the variability of RE and the cost implications?
3) How should we define "green power"? Should the definition be a function of its intended use, such as for producing green hydrogen or charging EVs? To what extent should regulations allow accounting-based banking of power (distinct from energy storage)?

This paper focuses on "green electricity" from the production or supply perspective and does not examine retail (consumer) green tariffs.[5]

2. Understanding RE Profiles and their Implications

This section presents background information on RE, its output profiles, and its value proposition in the Indian context.

2.1 RE Generates Less Than Most Other Sources on a Per-Megawatt Capacity Basis and has High Volatility

When comparing power generation options and their size, there are two important characteristics to consider. First, their capacity in watts (W), or kilowatts (kW), and, second, their energy output, typically measured in kilowatt-hours (kWh, or a unit of electricity). A power plant of 1 kW capacity running 24 hours a day would produce 24 kWh of energy in a day. To operate 24x7 at full load, it would need not just fuel supply (if required) but also a design oriented around continuous output, not to mention steady demand.

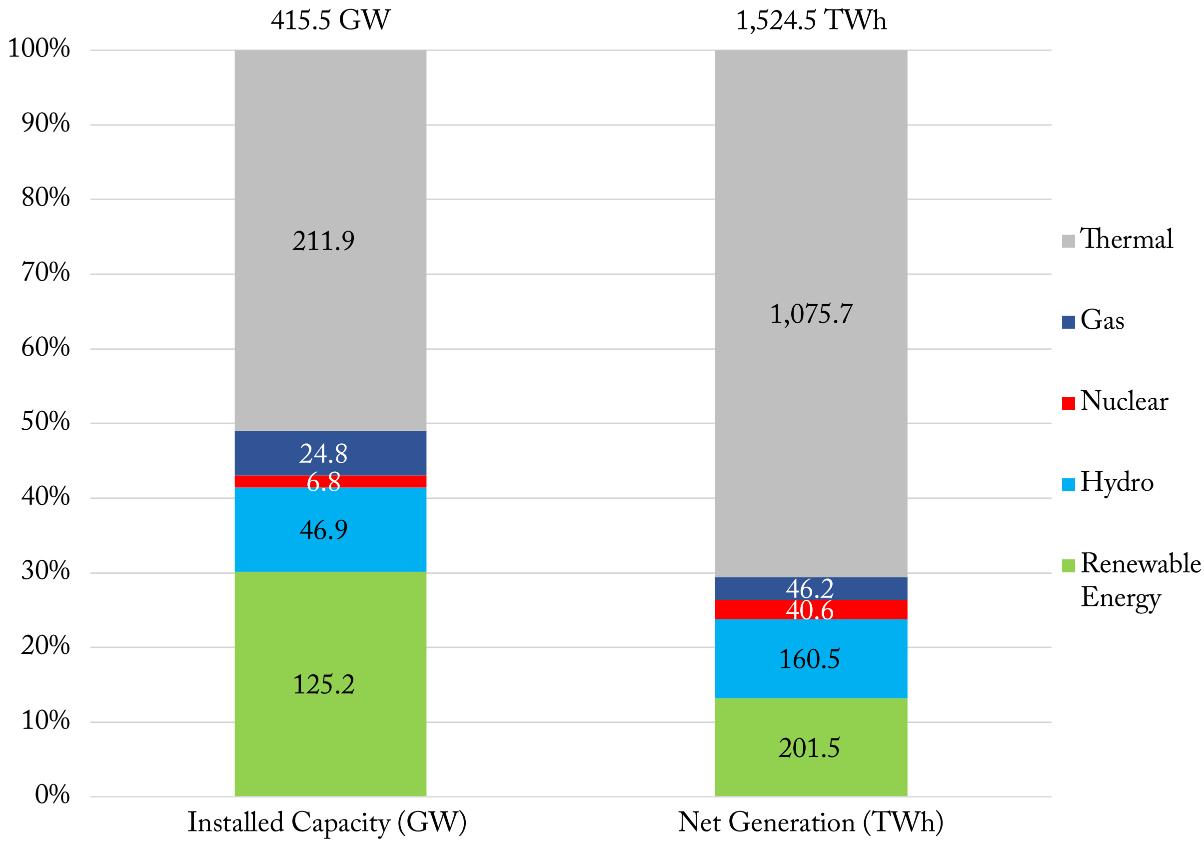
$$\begin{array}{ccccc} 1\,kW & \times & 24\,hr & = & 24\,kWh \\ Capacity & & Time & & Energy \end{array}$$

RE plants, within which we focus on wind and solar, are not only intermittent or variable but they are also a use-it-or-lose-it resource. In addition, they have a low plant load factor (PLF), also known as the capacity utilisation factor (CUF), which measures annual output as a share of the output based on a nameplate or theoretical capacity operating 24x7. Figure 1 compares India's grid electricity capacity with generation for 2022 (calendar year). It is evident the extent to which coal over-generates while RE under-generates compared to their respective capacities.[6] RE's share of net generation in FY2022–23 was 13.2%.

[5] The Ministry of Power (MoP, 2023) recently issued a notification for states to notify retail green tariffs, that too with a formula capping the prices. An analysis on retail green tariffs is the focus of another CSEP paper. It is worth mentioning that many of the issues in this paper also apply to retail green tariffs, such as how green is such electricity? Retail tariffs add more complexity because consumer prices are set by regulators to not just cover cost but to also allow for social welfare redistribution through cross-subsidies.

[6] For this figure, thermal power includes coal and lignite, but the latter is a tiny fraction of thermal capacity. Natural gas power plants might run on liquid fuels like naphtha if required, but such breakdowns are not relevant for our analysis of capacity versus generation.

Figure 1: India's FY2022–23 electricity capacity versus net generation mix—utilities (excludes captive power)



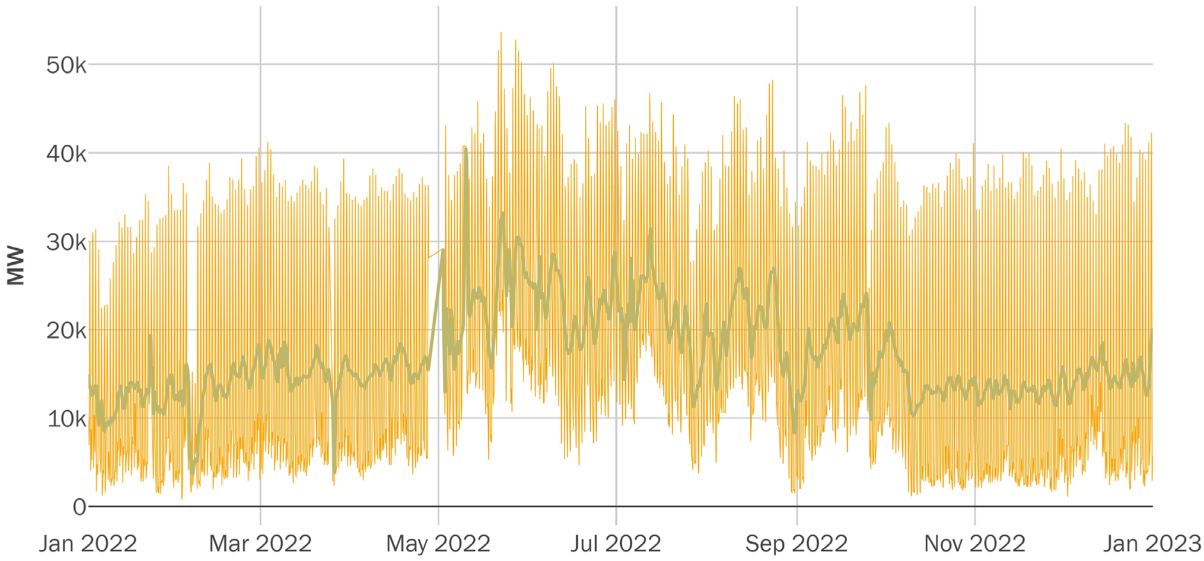
Source: CEA Monthly Executive Reports (March 2023).

Notes: The total installed capacity was 415.5 GW, while the generation supplied to the grid was approximately 1,526 TWh, also termed billion units or billion kWh. Official documents show gross generation by fuel, which is before auxiliary (in-plant) consumption, which is not available to the grid. The figure shown corrects for this, to give a better understanding of the relative usable outputs by fuel type. RE and hydro have very low auxiliary consumption, typically 1% or so, while coal can have as much as 9% auxiliary consumption. Without correcting for this, the gross generation of thermal in FY2022–23 was 72.0% of India's generation, but its share of net supply to the grid post-auxiliary consumption was 70.6%.

In most Central Electricity Authority (CEA) reports, thermal includes coal and lignite, with lignite just 3% of thermal capacity. Gas has about 25 GW of installed capacity, or close to 6% of total grid capacity as of March 31, 2023, but only produced 3% of net generation in the financial year. RE is predominantly wind and solar, with traditional (large) hydropower accounted separately.

This difference between capacity and generation also has strong time-of-day aspects and seasonality. Figure 2 shows the annual 2022 RE output based on MERIT India data captured at CSEP's carbontracker.in at a 5-minute resolution. The vertical lines roughly show daily output (365 lines, less any data errors). On many days the RE output falls close to zero (at some point in the night). Reading horizontally shows seasonality, and we can see a high-RE season (monsoon and a bit after). This has high wind power, evidenced, by a rise in the daily low.

Figure 2: India's RE output (2022) at five-minute intervals with the daily moving average

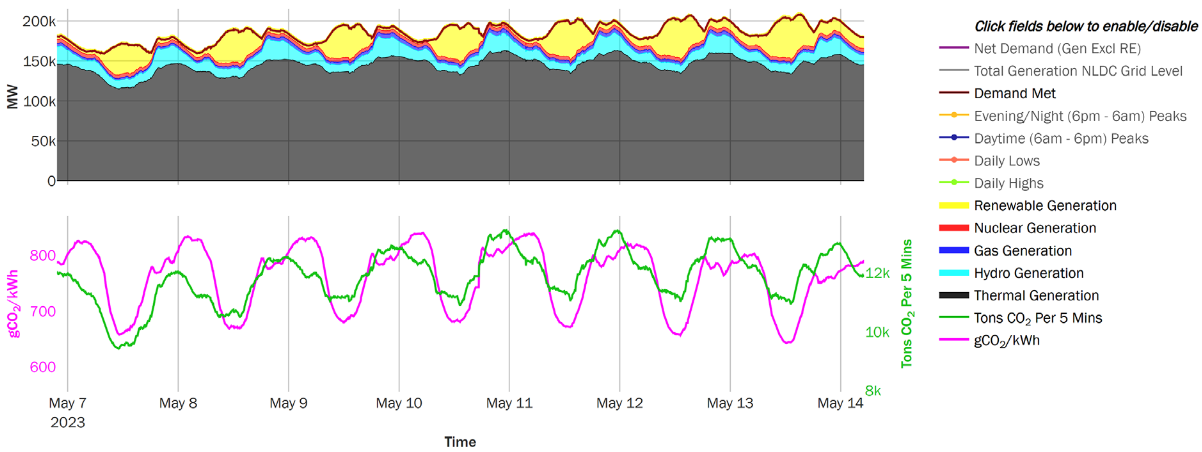


Source: CSEP's carbontracker.in (based on the government's MERIT portal, Merit Order Despatch of Electricity for Rejuvenation of Income and Transparency, http://meritindia.in).

Notes: The darker line is the 24-hour moving average. For methodological reasons, this understates RE output, as all RE plants are not on the real-time system, especially not smaller ones, but the trends are likely consistent. There are a few points with missing or incomplete data.

Figure 3 shows a zoomed daily profile of all supply technologies over a week in May 2023, which is close to the peak demand period of the year. We can see the inherent variability of RE (in yellow) and that of coal (in grey), which dominates supply.[7] The lower curve shows corresponding carbon emissions based on official Central Electricity Authority (CEA) emission factor multipliers. In January, the daily peak is in the morning but by the summer, the evening load rises measurably, invariably due to the use of air conditioning, leading to a daily bimodal shape.

Figure 3: Daily supply mix to meet demand (representative days; 5-minute resolution)



Source: CSEP's carbontracker.in (based on MERIT India data).

Notes: The carbon emissions are based on static emission factor multipliers per fuel published by the Central Electricity Authority (CEA).

[7] Due to data limitations (lack of instrumentation for real-time capture on older or smaller units), the RE output captured by such portals is 10–25% lower than the true RE output, but we assume the trends remain similar.

A good solar plant may produce only 25% of its rated output over a day, so a 1 kW solar system may produce roughly 6 kWh in a day, varying slightly by season and location. This makes sense, given that the output would be zero half the time (i.e., at night), and mornings and evenings would have a lower output than mid-day.[8] Wind power is even more unpredictable, varying not just across the day but also heavily across seasons. In India, a disproportional share of wind output is produced during the monsoons (Schwarz & Tongia, 2023). However, at a good location, wind can have a 30% PLF or higher, more so with newer wind turbines at higher hub heights, which are linked to larger turbine diameters and improved technology.

In contrast, traditional fuels such as coal can operate at very high PLFs, sometimes over 90% in a year. In practice, Indian fleetwide coal PLFs have fallen from a high of 78.6% in 2007–08 (a period when capacity shortfalls partially drove high PLFs), to mid-50s per cent in recent years (but recently inching back up). However, such national figures mask enormous heterogeneity. Pithead (mine-mouth) plants have much cheaper coal and consequently operate at higher PLFs. Nevertheless, even using a notional figure of 65% PLF, a 1,000 MW coal plant would produce about as much electricity in a year as a 2,500 MW solar power plant. We would, therefore, need to build many more RE plants for the same electricity output, the cost for which would be entirely up-front capital costs since RE has no fuel costs.

2.2 Load Factors, Duty Cycles, and the Economics of RE

End users typically want the cheapest electricity, but the previous section showed that different sources of power have different output profiles. If we are willing to (temporarily) ignore such output differentials, then costs can be compared across supply options using *total* but *average* cost metrics that add capital expenses (capex) and operating expenses (opex, mainly fuel for coal).

By undertaking such cost calculations, we find that the total costs of solar power are significantly lower than the total costs of adding new coal power. For solar, instead of doing the math on hardware costs and operating expenses, we have a flourishing market of developers whose projects reflect total costs. Bidding has unleashed competitive prices for solar power that fell below Rs 2/kWh but have since crept back up. A fair value is probably around Rs 2.4/kWh today. In contrast, there are far fewer bids for new coal plants. However, first principle estimates indicate a capital cost per unit of approximately Rs 2.5/kWh (assuming a healthy PLF) and an opex (mainly fuel) of under Rs 1.5/kWh for an efficient plant near a coal mine. In total, we can assume approximately Rs 4+/kWh for coal, including fuel escalation through the decade, thanks to a buffer in numbers as explained in the footnotes.[9,10]

However, the indicated cost of solar is only for variable RE (VRE), i.e., without any storage or ability to guarantee output. Such variability imposes additional costs on the rest of the grid for ensuring alternative supply that is needed but would have a lower output due to RE displacing it (e.g., solar in the middle of the day). These additional costs pertain not only to the cost of the alternative power capacity required but also to potential changes in fuel costs for these sources. Coal plants operating at a part load have lower efficiency and thus have a fuel cost penalty. Unfortunately, as of 2016, Central Electricity Regulatory Commission (CERC) norms only compensate for a 3% heat rate

[8] Due to new designs, where the DC panels are oversized compared to net AC grid feed-in, new solar systems in large farms can provide a CUF of 27+%, but this is a technicality irrelevant to our analysis.

[9] Assuming Rs 9 crore per MW capital costs for a new, efficient coal plant, at 65% PLF and 12% cost of capital amortised over 25 years, capital costs convert to Rs 2.02/kWh. We used a higher figure to be more conservative than CEA and factored a buffer for rising fuel/O&M costs.

[10] Rs 2,500/ton domestic coal as delivered at a short distance, including taxes/levies and at an efficiency or specific coal consumption of 0.55 kg/kWh, means a fuel cost of 1.375 Rs/kWh. Fuel costs will rise over time and hence we can estimate a total cost of Rs 4/kWh for a new coal plant with high efficiency, steady duty cycle, and a good location near cheap coal (see previous footnote for capital costs).

(i.e., efficiency) change for supercritical plants when operating at 55% of output (CERC, 2016), a compensation that doesn't cover practical changes in efficiency. Efficiency penalties are likely to be even worse if the plant has to ramp output up and down as part of its flexible ("flex") operations as opposed to operating at a steady lower output.

To properly understand the role of PLFs and their implications for the grid, we must consider the usage (i.e., demand) profile. PLF only tells us the output compared to a plant's maximum output as a notional straight line. But demand isn't a straight line. Hence, we must compare both sets of curves—output and demand.

The good news is that there is relatively more daytime demand that matches solar output than what occurs outside the solar window. For 2019, Tongia (2022) found that total RE in India had about a 35% overlap with demand, which is higher than the PLF of either wind or solar. This calculation is based on a comparison of a hypothetical pure RE system, which was scaled up until it touched the demand curve (i.e., with no storage and no curtailment (throwing away) of surplus RE). If the RE output and demand curves are scaled proportionally, we would still need 65% of supply coming from "something else" to meet demand. If we oversize RE to serve some of the demand, we would have periods where RE exceeds demand, but RE would then be able to meet more of the demand without needing storage.

Currently, the grid has a well-defined demand shape, but it is evolving over time. With a smarter grid and by aligning demand to when the sun shines (or wind blows), such as by using solar pump sets, there is no reason we should not have 40–50% demand coverage by VRE. One major wrinkle in this possible future is if residential air conditioning demand grows faster than commercial air conditioning demand. As homes need cooling mainly in the evening or overnight, this may shift demand to the latter part of the day, outside the solar window.

Other than the growing demand for electricity for cooling, the largest current demand growth driver, two of the largest new electricity demands in the future will be for EV charging and hydrogen production via electrolysis. These will also have duty cycles very different from today's aggregate demand profile.

"Green hydrogen" is made by splitting water molecules using an electrolyser, producing oxygen and hydrogen, *and* where the input electricity to split the water molecule comes from green energy. In contrast, almost all the hydrogen in India (and worldwide) today is "grey hydrogen", produced by steam-reforming natural gas (CH_4, or methane), thus producing significant CO_2 emissions in the process.[11] As of 2020, approximately 53% of Indian hydrogen was used for ammonia (fertiliser) production and 47% in refineries (Hall, Spencer, Renjith, & Dayal, 2020).

The cheapest green hydrogen could be achieved If we had cheap green power running 24x7, so the electrolyser could be utilised to its maximum capacity potential. However, as discussed previously, we do not have green output 24x7. This is a major issue that is discussed later in this paper.

For EVs, luckily, we do not need to charge them 24x7. Typical home charging would only need to be done once in several days, except for heavy users; public charging stations would also have more hours of charging. Thus, in theory, to be green we could align EV charging times with when the sun shines or the wind blows. For simplicity, we can focus on solar power, which is intuitively more predictable and easier to align with than wind power.

Before addressing the question of CO_2 emissions, a more direct issue is whether EVs can charge at RE-aligned time slots, say, mid-day. If the vehicle is on the move, as fleet users and taxis might be, then they cannot easily use solar to charge. In addition, as subsequently discussed in this paper,

[11] A small fraction of India's hydrogen is "brown hydrogen", which is produced from coal gasification.

storing solar via upstream batteries to provide on-demand green power to charge an EV or make green hydrogen isn't a cost-effective solution. There are also plans to deploy battery swapping for selected users, especially for commercial users or fleets, but these require modular battery designs and significant infrastructure. Importantly, these designs require extra batteries that can be charged—ideally with RE—while other batteries are used to drive users around.[12]

2.3 The Value of RE Depends on its Usage and Pricing Frameworks

This sub-section focuses on the value of RE, in light of the use of green power for applications like charging EVs or producing green hydrogen. This discussion is important because most RE for such use is unlikely to be dedicated, "behind-the-meter" (onsite) capacity, and, thus, such consumption would require significant grid interactions.

RE is a subset of generation options that distribution companies (discoms) can use to meet demand. Indian discoms buy power from generators predominantly through power purchase agreements (PPAs). These long-term contracts do not adjust the price based on grid dynamics or the value of generated power. Current frameworks that ignore the time-sensitive value of RE (supply side) and the dynamics of the grid (demand side) impede the growth of RE; discoms are sometimes reticent to sign RE PPAs as these only address a part of their demand needs.

Variable RE's value in a grid is limited by two fundamental issues. As its share increases, its marginal cost of integration rises and its marginal value declines. Both issues can be highly non-linear.

While there is a paucity of analysis on the true system-wide costs of RE integration, a CEA (2017) study estimates hidden or socialised RE integration costs at approximately 1.5 Rs/kWh. This estimate primarily considered the costs imposed on other generators and thus excluded the costs associated with peaking power supply for periods of non-RE-aligned demand.[13] Such periods of high demand, outside the solar (or RE) window, are critical for planning, and policies should focus on managing and, ultimately, reducing this demand, which is termed "net demand" in industry parlance.

Net demand is the demand remaining after subtracting the demand met by variable RE, where RE could be viewed as negative demand instead of supply. Too much RE could even lead to periods of negative net demand. This has already happened in California, as Figure 4 shows, where earlier, RE was merely lowering net demand in the middle of the day, creating what is famously called the "duck curve". Arshad Mansoor, president and CEO of the Electric Power Research Institute (EPRI) now calls this a "canyon curve" (Patel, 2023). For India, zero net demand is a few years away, but the practical limits of net demand will be reached much sooner than zero net demand because of extensive coal generation, which cannot be temporarily switched off in the middle of the day.

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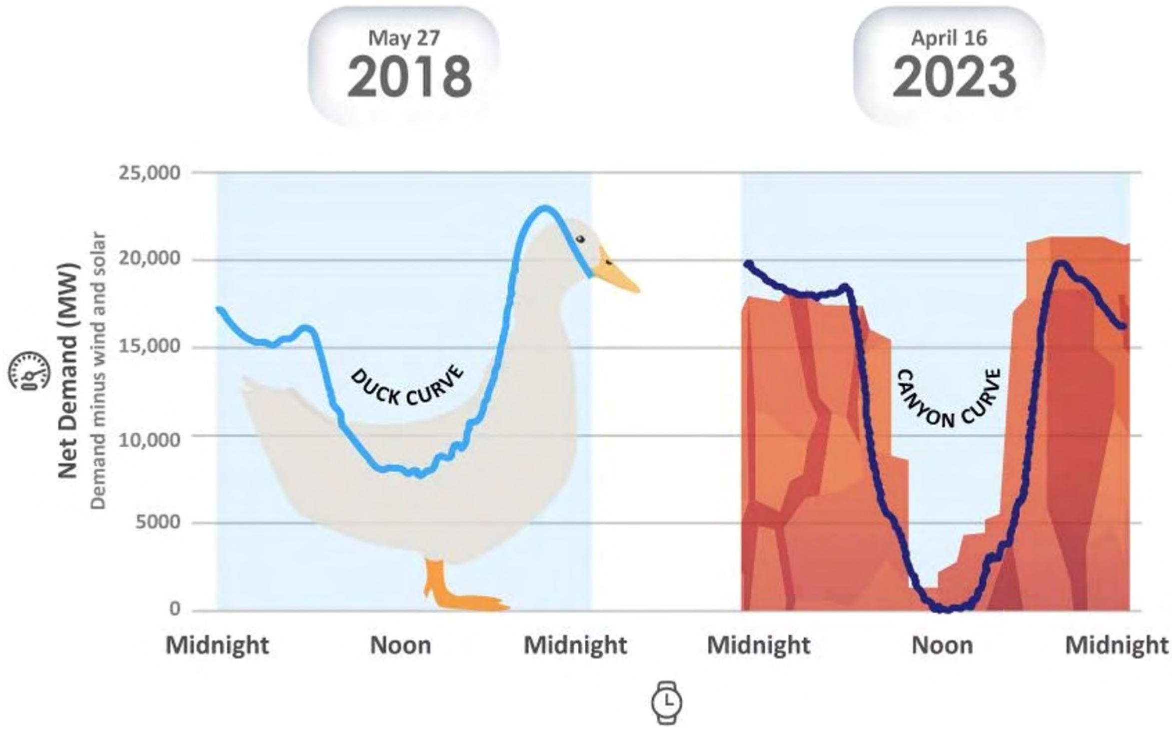
[12] Swapping may be easier for smaller batteries, such as for two- and three-wheelers. Based on current technologies, a bus would require a battery weighing approximately one ton, varying with bus weight and desired range.

[13] RE prices have since fallen, lowering the average net integration costs, but over time the net costs will rise again as more investments are required for grid balancing, grid stability, and transmission.

Figure 4: Impact of RE on net demand in California—from duck curve to canyon curve



Source: Patel (2023).

Variable RE also imposes other system costs as its share rises. There are growing costs for backing down alternative (coal) plants, increased wear and tear on coal plants, and the need for more transmission that would also have a low CUF.

When it comes to RE's value, in the short run, as long as the grid has sufficient capacity to meet demand, especially net demand, then to a load despatcher, the value of RE is equal to the difference between RE costs and the fuel displaced—the alternative capacity is already built and is a sunk cost. A study by Parray and Tongia (2019) shows surplus coal power plant capacity in India to meet several years of demand growth.

Given growing demand, new RE can also avoid the capital costs of constructing non-RE power plants. However, VRE cannot avoid all alternative capacities because of its intermittency. Hence, its capacity value is not straightforward to calculate. Appendix 1 presents a framework for comparing RE and coal, adapted from Tongia (2018a). Instead of a traditional, simple crossover between rising coal prices and declining RE prices over time, it shows a series of competitive steps, factoring in marginal versus average costs, times of day, location, etc.

In terms of declining value for RE, as its share rises, it is intuitive that adding RE can displace coal or gas, and the most expensive plants fuel-wise would be displaced first. However, with rising RE, one would soon have to displace cheaper power plants, i.e., coal plants near or, ultimately, at the pithead.

In the short run, this method of valuing RE based on avoided fuel costs would apply across almost 90% of today's Indian grid supply that relies on PPAs. Such PPAs for coal typically separate the fixed (capacity) charges from variable (fuel) charges with a so-termed two-part tariff. In contrast, PPAs for RE are single-part tariffs since RE has no fuel. Therefore, when would a state load despatch operator choose coal power supply over RE? They would compare the *variable* cost of coal with the *total* cost of RE. This may appear distorted, but it reflects the reality that RE supply is, at the margin, a new build, so this is one way of signalling the system's demand for more RE (before considering renewable purchase obligations (RPOs) or mandates). If a grid operator needed both the coal and the RE supply, then the comparison is moot. At least up through 2022, India had sufficient coal power plant capacity.[14]

Even if RE appears expensive to a grid load despatcher because of the reasons above, norms indicate that RE should come first in the merit order (incremental least cost) despatch and be treated as a "must-run" resource and never curtailed, except for emergency reasons. Even if RE did not have such norms, in theory, it would still come first in the merit order since it has no marginal (fuel) cost.

In Europe and North America, numerous regions have wholesale markets that set an hourly (or other time block) uniform supplier price based on the last cleared price. Adding more RE shifts the intersection of the supply and demand curves, lowering prices for all generators. Technically, this holds true for adding any supply, but RE is most of the new capacity addition and has zero marginal cost, so it has a preferred status in the merit order stack. Partly because of subsidies based on production (often as a production tax credit, or PTC), some regions routinely arrive at negative prices for some periods. This dynamic of lowered value due to RE is already measurable. For instance, in 2020, the combination of high RE and depressed demand due to COVID (along with local issues sometimes) led to 4% of hours experiencing negative prices in the US (across wholesale nodes), and some regions even saw negative prices for 25% of hours (Seel, Millstein, Mills, Bolinger, & Wiser, 2021)! For India, the VRE share envisaged by 2030 (close to half the electricity) is higher than in many such markets in the world that have already jumped into negative pricing territory.

Zero value for RE would not be just due to low demand growth compared to the growth of RE supply (eventually leading to negative net demand). There are also grid technicalities that exacerbate the decline in RE's value. First, much of India's RE growth is from solar, whose output is highly correlated across the country. Second, India is highly dependent on coal plants, whose output cannot ramp up and down quickly and which face technical limits in running part-load (flex) operations. Coal plants cannot be switched off and back on quickly, not without severe economic penalties. Thus, if we need coal to meet the evening peak demand, a minimum coal output will also need to be produced in the middle of the day, hastening the occurrence of surplus RE well before we enter negative net demand territory.

Ultimately, any reduction in RE's value could risk translating into lowered incentives for scaling up RE, which could potentially lead to more emissions if this results in more coal-powered capacity.

While some reduction in RE value as its share grows is inherent to its nature, market design (or simply just PPAs) will also be a factor in determining its value in the coming years. The lack of wholesale markets for most power supply transactions in India means that adding RE will not lower the average price nearly as much as in some other countries. The flip side is that when India needs to convert RE into firm supply by adding storage and thus pay a premium, it will not raise average prices nearly as much either.

3. Handling the Limitations of VRE

Extensive modelling evidence (e.g., Tongia, 2022; Abhyankar, Deorah, & Phadke, 2021) shows that high wind and solar power is cost-effective for India, even without storage. At high levels of RE output, as targeted by 2030, there will be periods where there will be "too much" RE to integrate (in the order of 10-20 per cent of the RE output in some scenarios).

There are four non-exclusive options for managing the increasing share of RE in the grid, eventually to the point of surplus:

[14] Sufficient coal power plant capacity to meet demand in the near term assumes (1) there is enough coal at the power plants and (2) other generators supply up to their best abilities, including hydro (which needs reasonable rains) and gas (which needs affordable gas supply). Violations of these assumptions are the reason for the periodic electricity supply crises post COVID-19.

1. *Change the demand profile to align with RE supply*, e.g., through solar pump sets, consumer education, alignment of shiftable loads, smart grids, and demand response (including through pre-cooling buildings). This will help measurably, but even after exhausting these possibilities, it is likely that there would once again be too much supply. Today, for the most part, India's grid lacks signalling (pricing) for time-of-day, both at the wholesale procurement level and at the consumer retail level.

2. *Curtailment = throw it away*. While this may seem a waste, this is cost-effective because the price of new RE is typically very low. The volumes typically planned for occasional curtailment are usually only a few per cent, and even at higher percentages, it may still be worthwhile. For example, 10% curtailment means only an 11% increase in RE cost,[15] which still leaves this as the least expensive new build. Global literature supports such "strategic curtailment" that goes hand in hand with overbuilding, which increases firm supply (Perez, Perez, Rábago, & Putnam, 2019).

3. *Make coal plants more flexible.* While this cannot be done overnight and has a cost, retrofitting can lower plants' part-load operational limit, allowing greater backing down of coal to accommodate more RE.

4. *Add storage, especially a battery or pumped hydro*. Unfortunately, storage is still expensive, and the true costs of storage depend on the duty cycle. For seasonal storage, pumped hydro may be superior to a battery. For daily use, batteries are best clubbed with solar, which is relatively stable across seasons compared to most wind in India. The India Grid 2030 model by Tongia (2022) found that the real value of storage is not in avoiding curtailment per se but rather in adding firm supply to periods of peak demand, especially evening periods of maximum net demand.

We expand on some of these options in subsequent sections.

RE-Aligned Demand has Multiple Design Options: The Example of Solar Pump Sets

Evaluating duty cycles and RE alignment can help us re-think current schemes such as solar pump sets. There are three dominant models of solar pump sets deployed in India. First, we can have solar panels placed at the pump set, like under the PM-KUSUM scheme. The problem is that on some days, the farmer does not need water. To maximise the use of solar energy, the power from the pump set must be fed to other users; the system cannot be standalone, at least not cost-effectively. Second, we can have solar feeders with bulk solar at an aggregated level, such as near or at a sub-station (Maharashtra is a pioneer of this model). This allows easy use of last-mile infrastructure to send power downstream or upstream. The third model is the one Karnataka deployed starting in November 2018, where it changed the supply schedule for agricultural feeders to match solar supply. The solar could come from large solar farms, which have the cheapest solar, and feeder segregation makes it easy to deploy this scheme with no additional infrastructure required. Agricultural feeders were already on a schedule or roster in the past, but now the optimal time of (say) eight hours daily supply was no longer night-time off-peak supply but mid-day instead. This may be the cheapest option for a number of regions. These examples highlight that we must be cognisant not just of the time-of-day but also of the *location* when considering energy services and green supply.

15 Mathematically, curtailment by x raises RE costs by $(\{\frac{1}{(1-x)}\}-1)$.

4. It's not Easy to Calculate CO_2 Emissions from Power Consumption: Average or Marginal Emissions are Insufficient (and Complex) Measures

4.1 Emissions in the Short Run

When you plug in any device, for instance, a water heater or an EV, what are the CO_2 emissions from this usage? The answer depends on how the emissions are measured.

In the short run, the answer is simply based on the incremental supply that meets this incremental load. In the US, this is often natural gas, but in India, it is almost always coal. Coal is India's swing producer, and this also applies to reductions in load, as was the case during the COVID-19 lockdowns. The exceptional reduction in demand during the lockdowns was matched overwhelmingly by a reduction in coal generation (Parray, 2020).[16]

India lacks sufficient domestic gas supply and, thus, gas-based generation is far lower than gas-based capacity as Figure 1 showed. Hydro, while it may respond to demand changes rapidly, has an annual output that is limited by rainfall (and, to a lesser extent, snow melt). If hydro ramps up output rapidly to match the rise in demand, then such supply becomes unavailable later out of its reservoirs; the annual use of hydro does not change.[17] Nuclear power is, in general, inflexible in terms of output (though France has pioneered more flexible nuclear units). Within this challenging context, RE is not just use-it-or-lose-it; it has a "must run" status for most grid operators (load despatchers), subject to grid security conditions. Thus, coal remains the swing producer for India. *And this is true even in the middle of the day when solar output is maximum.*

Even if I plug in my EV to charge in the middle of the day, that (normally) does not result in more solar supply. This is because solar should be maxing out its output, independent of load. The only time this would not be true is if we had surplus solar and it was being curtailed. Currently, curtailment is limited in India based on RE's modest scale thus far (RE accounted for 12.7% of power generation in 2022, according to CEA data). Most of India's RE curtailment happens in niches due to transmission issues, often local, or other reasons unrelated to aggregate electricity demand or the ability to consume such RE. Solar (like wind) runs to the best possible extent since it has no fuel cost and, as discussed earlier, is first in the merit order despatch.

4.2 In the Long Run…We Will Have a Different Grid

However, the short run does not tell the whole story since the grid is evolving, overwhelmingly by adding RE in recent times. This complicates how we measure emissions, e.g., via short-term marginal emissions or average emissions. As Appendix 2 details, because fossil fuels are today's swing producer, (short-term) marginal emissions are usually worse than average emissions. However, because the grid is getting cleaner with more RE, the average emissions are declining. There is extensive literature that points out that neither of these are complete measures alone, even before considering the evolution of the grid.

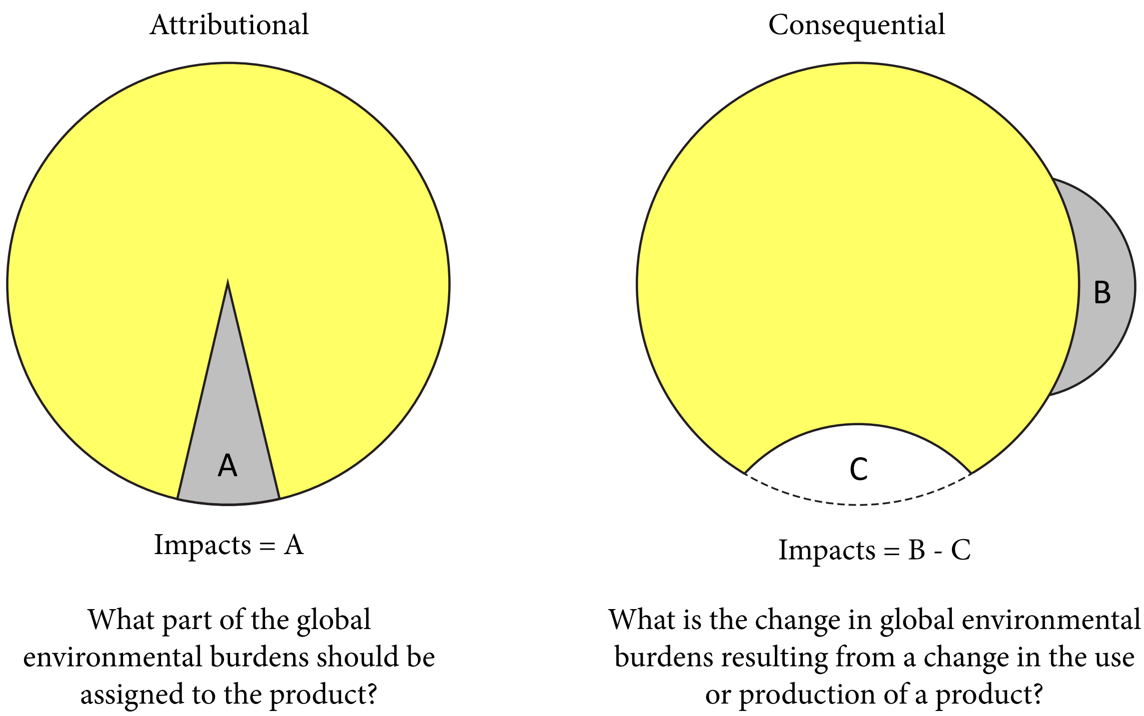
The US National Academies recently released a consensus study on the complexities of measuring emissions from low-carbon fuel use (NASEM, 2022). It points out that there are two main types of life cycle emissions that can be calculated, and these are not comparable as they ask different questions. The first is attributional life cycle analysis (LCA) emissions, and the other is consequential

[16] Natural gas usage was already low, and most of the gas that supplied power then was either based on domestic (cheaper) gas and/or was being used for peaker duty cycles.

[17] Complementary research at CSEP (forthcoming) shows how in many seasons, hydro is used more as a peaker (for balancing evening peak demand) instead of focusing on short-term ramping up (or down) requirements.

LCA emissions. Figure 5 shows how they appear conceptually. For simplicity, for much of this paper, we focus on emissions from the *end use* of fossil fuels and not on life cycle emissions from the underlying infrastructure or fuel transportation.[18]

Figure 5: Two types of life cycle analysis emissions: Attributional and consequential



Source: NASEM, 2022.

Attributional emissions are an apportionment, in some ways close to average emissions, based on dividing emissions from the use of a product out of the emissions for the whole world (or country if appropriate). In contrast, consequential emissions are close to marginal emissions and reflect a change in emissions with the use of a product (or stemming from a policy) *at a systems level.*

As a simple example, say we change our fridge to a more efficient model—from one using 300 kWh/year to another using 100 kWh/year. The attributional yearly emissions are independent of each other and are now 100 kWh/year instead of 300 kWh/year. In contrast, the consequential emissions have the net impact of a reduction of 200 kWh annually (= 100 – 300). A negative number for consequential emissions simply means an improvement, and does not mean absolute negative emissions.

Attributional emissions are always equal to or, more likely, greater than zero. Consequential emissions can be zero under the right conditions or even negative for some changes in the use or production of a product, especially with efficiency. However, for new supply to meet new demand, consequential emissions are more typically positive even after accounting for any reductions (which are portion C in Figure 5).

To understand the differences and some of the complexities, let us compare two hypothetical power systems for a country with similar demand—one that is 80% RE and 20% gas and another that is 20% RE and 80% gas. (We assume gas for this thought experiment since it is more flexible than

[18] Emissions are not just carbon dioxide but can include a range of other air pollutants, not to mention broader externalities during manufacturing (and usage). This is one reason to consider more than just CO2 emissions for comparing EVs versus internal combustion engines.

coal and can be turned on or off easily, and we ignore issues of RE variability.) Let's add a new load, which we assume the existing system can handle without requiring a new buildout of capacity. Let's also assume that we do not have surplus RE that is being curtailed, and so the demand is over 80% of the total system size. In such a case, the swing producer is gas. In this thought experiment, the consequential emissions from the added load are identical in both systems because both require gas for all the incremental supply. In contrast, the average emissions for the two grids are very different—the high RE system is much cleaner. If we apply attributional emissions analysis based on an average, any load in the first system has lower emissions.

A key question is whether an end user can claim attributional emissions in isolation. Coming back to the example of the Kochi airport, we know that the overnight use of non-solar power means a fair amount of CO_2 emissions. There is also surplus solar generated by the airport that is for another user (going through the discom). But the attribution of the surplus solar is the challenge. *The other user and the airport cannot both simultaneously claim zero emissions under any consistent framework*.

If we apply a consequential emissions framework to the airport, we have higher emissions in the evening, but we can also have a lowering of emissions in the day *assuming all this solar is incremental that would not be built otherwise, and it avoids coal power.* As literature observes, such displacement is difficult to prove, more so since we lack counterfactuals. In the airport example, this also requires the other user to have demand entirely coincident with the surplus solar.

Deployments such as Kochi airport's solar can have offsets (portion C in Figure 5), but this applies only while India has room to grow variable RE that displaces coal generation. It is only a few years away when this will no longer be true, and India enters surplus RE conditions. Thus, consequential emissions accounting will not keep India at zero emissions, not unless many conditions are met.

Consequential emissions are not the best tool for directly apportioning emissions across a mix of users; attributional analysis is better suited for the task, which requires us to look at averages. This is because it is difficult to attribute incremental emissions to incremental demand without first asking if the increment is due to a change in use (existing systems) or a change in the system (new builds).

Hypothetically, imagine we have a small grid with 100 EVs and no other load, and we add one more EV to the mix. From a supply perspective, merit order despatch would run up the supply curve until the last demand is met. Thus, the supply curve may start with a mix of RE/nuclear (downscaled for illustration purposes), which are "must run," with nil or low marginal costs, followed by hydro (low marginal costs but limitations on its duty cycles), and then coal.

The question becomes is it appropriate to label the first EV as 100% clean and the last EV as 100% coal with high CO_2 emissions? There is a consistent framework that indicates that for the state of supply with low load, the grid was clean. However, as the load grew, the grid became dirtier, and it was the incremental load that led to incremental emissions. But this is based only on incremental *use* and ignores incremental *buildouts* of the grid. If we are adding substantial new demand, then one could claim that the incremental new build of supply is based on the new demand, and hence, whether we add gas or coal (or RE) is what matters for attribution, more so if we do this on a time-of-day basis. In contrast, if we are simply considering the already built grid and which supply source turns on when, then averaged accounting would be appropriate.

The example in the preceding few paragraphs illustrates why we should keep total emissions as the measure of interest. The appropriate way to think of long-run emissions is to compare the total emissions for two different optimised states of the grid with different levels of load (NASEM, 2022). This is not easy and requires detailed grid models.

Adding demand usually adds emissions since we need more supply unless we can ensure that all the new supply is zero carbon. The key factor to consider when quantifying emissions is *additionality.*

The short run may tell us whether we have higher or lower emissions based on the grid at hand, but the long run must also factor in the grid that we will (or could) have in the future.

India, like most other countries, is planning to add significant VRE because it is cost effective. Such growth is independent of "clean energy demand", be it from EVs, green hydrogen, or simply any consumer seeking to use clean energy. If we cannot have green supply additionality, then so-called green demand does not lower emissions—it simply re-allocates emissions across consumers. Thus, any industry or company that claims to use green power, unless it has its own RE or contracts for dedicated, *additional* RE, is simply making itself greener on paper while making someone else less green.

Any benefit of additional solar capacity by an end user, beyond what they direct use themselves, must be considered with two pieces of caution. First, if there is a demand for solar power (specifically, power at times matching solar output), then we could easily have a smaller solar build by the airport (with no or limited surplus to export) and some other developer could put up commensurate solar capacity elsewhere. Stated another way, is Kochi airport's solar truly additive? In the short run, while India has headroom to grow VRE, it might be. Second, in a future where solar production has reached the maximum that the grid can absorb without needing storage (i.e., India enters a regime of surplus RE and curtailment), then the value of the solar is even lower, perhaps even zero.

Ultimately, it is the demand profile that matters and how it aligns with the grid's supply mix. New demand is likely to push supply up the emissions curve, especially if the times of day of demand do not align with RE. Kochi airport's demand would be relatively flat over the day and the year. No amount of on-site solar capacity addition reduces its demand outside the solar window, demand that is most cost-effectively met by coal in the near term in India. Such a demand would thus raise *total* emissions, even if the grid's *average* emissions per unit decrease due to the solar build. These can only be offset up to a point by over-generation mid-day.

Appendix 2 details the nuances of measuring and estimating emissions, including generalised supply-emissions curves. Frameworks for measurement are important because we cannot measure emissions in advance, such as when planning or framing policies, and such metrics help guide policies (and keep accounting honest).

5. How Does one get a Green EV or Green Hydrogen? Frameworks and Economics Matter

The most straightforward indisputable technique to ensure the additionally of green power is if a consumer has dedicated, new RE capacity. This could be as captive power, which co-located would be "behind the meter" generation by the consumer. If this is offsite, transmission entails a technical loss of several per cent, varying by location, and hence, the green power production should be sufficient to match delivered power demand.

However, even if the supply is green, this will not provide a steady or firm output, for example, to produce green hydrogen or charge an EV on demand.

5.1 Measuring Emissions is More Than Just an Academic Exercise: The Example of Support for Green Hydrogen

Being "green" is more than a label. It has implications for compliance with regulations or eligibility for governmental support.

Most current plans for green hydrogen in the US focus on grid-connected RE instead of co-located or behind-the-meter RE. The US Inflation Reduction Act (IRA, which is heavily a climate change policy based on cheaper and cleaner energy) has a sliding scale for eligibility for a 3 $/kg production tax credit (PTC) for green hydrogen, depending on the level of CO_2 emissions from the production process.

India is reportedly considering limited support of 50 Rs/kg of green hydrogen, about 0.6 $/kg, falling to 30 Rs/kg by the third year (Baruah, 2023). This is in addition to central government support for manufacturing.

Table 1 shows the CO_2 emissions based on various techniques ("colours") of hydrogen production and sources of power within electrolysis-based hydrogen. It also shows the emissions limits allowed by the US under the IRA for PTC eligibility.

Table 1: Hydrogen production from various techniques and corresponding emissions

			Electrolysis with RE	Electrolysis with electricity from the grid (average)			USA IRA thresholds for PTC	
	Grey H (Directly from natural gas)	Blue H (Natural gas with carbon capture)	Green H (Pure RE supply)	US	Germany	India	Limit for full benefit	Maximum limit for partial support (sliding scale)
Avg. Electricity Emissions ($g\text{-}CO_2/kWh$)	Not applicable	Not applicable	0	424	336	708		
H-production Emissions ($kg\text{-}CO_2/kg\text{-}H$)	~10	3–7	0	19.9	15.8	33.3	< 0.45	< 4

Source: Grey hydrogen (H) data are from Ricks, Xu, & Jenkins (2023), blue hydrogen ranges are from Longden, Beck, Jotzo, Andrews, & Prasad (2022), varying with emissions, and grid electricity emissions factors are from CarbonFootprint (2022) for consistency reasons and are 2019–2021 ranges. For India, the figures are close to the number that was calculated at carbontracker.in using CEA underlying data.

Notes: These figures are only for direct emissions from the use of fossil fuels and ignore manufacturing, transportation, or other life cycle emissions.

This assumes 47 kWh/kg-H electricity is required for electrolysis, which translates to an efficiency of approximately 70%. A major factor for natural gas-based (grey or blue) emissions is the level of leakage across the natural gas chain, made worse due to the high global warming potential of methane (and the use of an appropriate correction factor to arrive at CO2-equivalent). For blue hydrogen, there is uncertainty on how much of the CO2 produced can be captured and stored. This range caps at 90% capture but builds thus far are much lower in their capture efficiency and hence lead to the high emissions range, as shown.

IRA = Inflation Reduction Act (US); PTC = production tax credit.

The US IRA has a sliding scale, and the full PTC of $3/kg-H is for emissions under 0.45 $kg\text{-}CO_2/kg\text{-}H$. To achieve such low emissions, blue hydrogen would need to have perhaps over 95% CO_2 capture efficiency, even before factoring in typical (instead of optimal) levels of upstream fugitive emissions of methane. The IRA tax credit declines as emissions go up, to the last tier of 2.5–4 kg CO_2/kg-H, which would allow extensive blue hydrogen to get benefits, but at a much-reduced rate of 20% of $3/kg-H (Cooper, Fleming, & Perlman, 2023).

Within electrolysis-based hydrogen, if we had green hydrogen based on RE alone, the emissions would be zero, at least from the direct energy used.[19] On the other hand, what if we used the grid so that one could have steady (~24x7) power? We can compare the US, Germany, and India for average grid emission factors (per kWh), with resultant average emissions per kg-hydrogen as shown in Table 1. Emissions would vary by the grid but they would be even higher than from grey hydrogen!

Most importantly, no grid, not even the relatively clean UK grid (not shown), would come close to qualifying for US PTC credits. In such a case, what happens if we use the grid "partially" (or even in general) but also over-generate RE in some time periods? This is a vital question that at the time of analysis awaits clarity from the US government.

Experts are demanding strict criteria for green hydrogen, specifically (1) *additionality*; (2) *deliverability*; and (3) timeframes for matching RE supply and use, specifically *hourly matching* (Ricks *et al.*, 2023; Fakhry, 2023). These criteria are not new to green hydrogen but green power supply overall.

Additionality is somewhat straightforward. Without new clean supply to meet the new load, any use of "green power" would just be a displacement. Kochi airport can claim additionality for their solar panels, but only on average, i.e., not at all time periods.

Deliverability is also well understood. If one is using RE offsite, it must be delivered in a grid that is not congested. Being offsite may be helpful from a supply perspective because the co-location of RE facilities with the electricity consumption may not be optimal from a windiness/sunshine perspective. This also implies that the RE can be going elsewhere, and, in fact, at an electron level, it certainly will go elsewhere, since electricity flows as per physics, not contracts. But if someone wants to claim that it is their additional offsite RE that is powering their end use, their consumption has to perfectly match the variations in RE output, and grid-level implications would have to be factored in.

Any increase in transmission carries a cost. However, currently, interstate RE transmission in India enjoys a waiver of transmission charges, which are socialised across all users. This does not make RE power's interstate transmission free. It just means someone else is paying for it, perhaps Rs 0.50–0.80/kWh, or even more for very long distances. There are a few studies on the scope for hydrogen in India that also examine issues concerning the location of hydrogen hubs (e.g., Hall *et al.*, 2020), primarily based on supply chains for industries using hydrogen. It is unlikely that any study has also optimised electricity transmission, as well as the locational impacts of wind and solar by time-of-day and seasonality, to arrive at an even more constrained optimisation solution. Several proposed hydrogen hubs are near the coasts for export reasons. But where is the nearby RE?

How should we think about *timeframes* for using the grid and measuring the emissions? One technique relies on the time period of reconciliation. For instance, if we only ran a hydrogen electrolyser during the day using the grid, then we could apply the average grid emissions for such periods, in contrast to an electrolyser only running overnight, which would have higher (hourly) emission factors in India (and many other countries) because the night loses solar power supply. Table 1 illustrates that even though this is unlikely to be enough to be truly green, we would at least be greener. A daytime user could also have only incremental RE supply and match consumption accordingly, which would be green, but a downside is that the CUF would be modest because of RE's low PLF.

[19] It is worth emphasising that most calculations, including these, focus on direct energy emissions from fossil fuel combustion, a common measure that excludes lifecycle emissions such as those needed to build infrastructure. This is typical in many accounts, and thus we measure solar and wind as "zero emissions," which is true at the point of energy usage. Adding life cycle emissions does not make fossil fuels' emissions lower compared to wind or solar, it typically only reduces the difference in some cases. However, there is a marked difference in life cycle emissions when it comes to hydrogen production. So-termed "blue hydrogen," made from methane or natural gas, where the CO_2 is captured and sequestered, still has high global warming emissions, primarily due to the non-trivial "fugitive emissions" from natural gas extraction and transport (Longden, 2022; Howarth & Jacobson, 2021).

What should the right period of comparison and benchmarking be? Unrestricted grid use would be like the annual average, and thus, we would have very high emissions. Real-time matching is not feasible in practice and might be unnecessary; Ricks *et al.* (2023) found hourly matching to be close enough to full matching in emissions. Their studies for the US indicated weekly matching would mean significant fossil fuels getting used. Thus, they found that a good (and IRA-compliant in the spirit of the law) system would use hourly matching.[20] However, hourly matching, especially for a steady load such as a data centre that cannot change usage based on grid conditions, would raise prices as the threshold of hours of clean supply rises; for instance, first from cheaper VRE to more expensive VRE, and ultimately to requiring storage (Dyson, Shah, & Teplin, 2021).

Ricks *et al*. (2023) also found that hourly matching for the US western grids would mean that the electrolyser CUF would not be near 100% usage as the system does not have storage for 100% hourly green supply. On the other hand, the CUF could be more than the 40–50+% expected from pure wind and solar. Having supply from other non-carbon *additional* (new) sources can improve the CUF further.

India's green hydrogen policy permits a 30-day banking period with the distribution company (discom) for RE power, and it would still qualify as green hydrogen (PIB, 2022a). This is, by many measures, a lax standard, which inherently implies that a significant amount of fossil fuel will also be used.

It could be argued that oversizing the RE means such RE helps someone else become greener mid-day, but this is an accounting choice and needs strict criteria even under a consequential emissions framework. Even with a generous consequential emissions framework, such excess RE at specific times of the day lowers the growth of fossil fuels, perhaps even down to zero growth, if there is full mid-day fossil displacement from the excess RE, but it does not eliminate fossil fuels. Further, if a primary user does claim this is green hydrogen, then another user of such over-generation of RE cannot also be green.

Simply put, we must examine the total portfolio of emissions, including time-of-day implications and corresponding optimal supply. If we, say, create EV charging demand primarily concentrated in the daytime, that would spur or facilitate far greater solar power. To make sure we align demand with green energy supply and also maximise the growth of green energy capacity, we need new signalling such as time-of-day pricing schemes; these will be required both for generators and consumers.

For hydrogen production to truly be "green", we need to also consider life cycle emissions. For grey hydrogen and even blue hydrogen (with carbon capture), there are significant upstream emissions in the production and transportation of methane, many of which are not well accounted for and are termed "fugitive" emissions. While it may be convenient and quicker to estimate end-use emissions, proper accounting norms should at least factor in the *direct* life cycle of emissions, such as fugitive emissions, even if we do not use a full input–output level analysis of emissions (such as emissions from the steel used in infrastructure to transport fuels).

[20] Some analysts suggest that even hourly matching may not be sufficient for examining grid-level impacts at a system level. Per discussions with experts at the energy and emissions non-profit WattTime, who were cited in a recent *New York Times* article on the energy and environmental impacts of Bitcoin mining (Dance, 2023)—another steady load striving to be green—hourly matching can be a proxy for the system-level optimisation, but it may sometimes not be sufficient. Consider an example where the grid is running on a combination of gas and coal at the margin. Hourly matching does not tell us the value of switching off consumption across different time periods when the rest of the system may have a choice whether to displace gas versus coal. It may (hypothetically) be better to run the load more during a period of more marginal gas use if it could be compensated with lower demand during a period of more coal use at the margin. What is needed (but hard to measure) is causality of supply from demand, even if it is matched hourly. For more information, see their paper on marginal emissions modelling (WattTime, 2022).

5.2 Can we Raise the CUF of Green Energy? Option 1: Blending (Hybrid) RE—Good Value

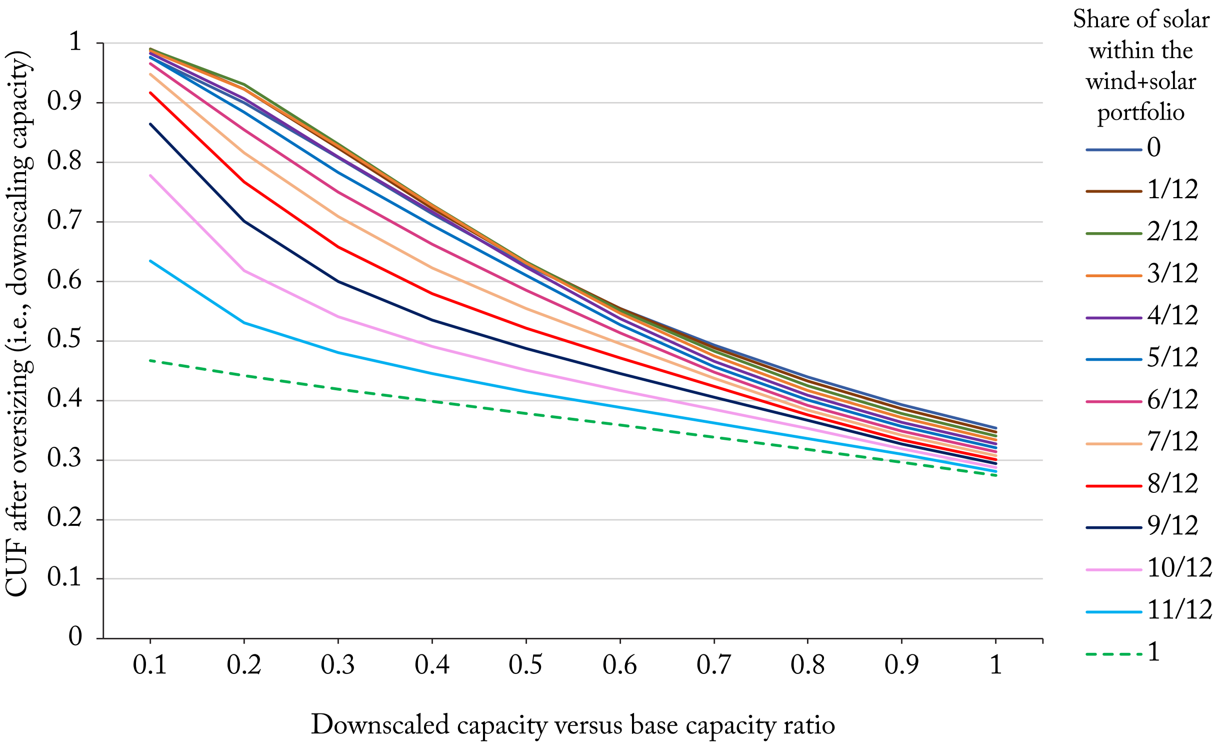
The need for additionality and time-of-day matching closely mirrors the PLF limitations for VRE. We cannot change the nature of the sun or wind, but there are system redesigns for raising the CUF of wind and solar generation. Using wind and solar data for 2019, built up as part of other CSEP studies using carbontracker.in, we can examine to what extent wind and solar are complementary and to what extent we can oversize and blend wind and solar.

Data for 2019 showed that wind is partially complementary to solar, but not purely. For instance, if we have a new 1 MW solar farm and a new 1 MW wind farm, with CUFs of 25% CUF and 33%, respectively, the base total would be a 2 MW system with a CUF of 29%, which is in between. But, instead of treating this as a 2 MW system, because of part complementarity, we would be better off considering it as a, say, 1.5 MW system when it comes to end-use sizing. This is an improvement because we would rarely have simultaneous peak wind and solar output and would therefore match the system with a 1.5 MW hydrogen electrolyser plant. If there were no other use for such RE, we would have a small amount of surplus RE output above 1.5 MW, but such power could be potentially sold elsewhere. However, for our conservative calculations, we assume it would be curtailed. This is because, in the long run, we assume our system would be surplus when the rest of the grid would also be surplus (such as mid-day or in the windy season), and hence, we assume nil value for the surplus.

Such wind and solar blending, combined with oversizing the RE, would raise the CUF of the recalibrated or downscaled capacity because we are now considering a reduced aggregate capacity as available to the user (like an electrolyser) instead of the simple sum of the wind and solar capacities. Figure 6 shows the increase in CUF for a range of oversizing RE with different solar:wind ratios. The oversizing is measured by rescaled RE size, which is the derated capacity compared to the simple sum of the RE capacities. The starting point is a downscaling ratio of unity, on the right edge, which means no oversizing. Higher oversizing or downscaling capacity (moving leftwards from unity) increases the system CUF because the denominator, i.e., the total maximum output if the new downscaled capacity operates in full throughout the year, is smaller.[21]

[21] These calculations build off data and analysis on the grid in 2030 by Tongia (2022). The study incorporates observed and calculated 2019 time-of-day outputs of wind and solar for load shapes and blending analysis but uses projected future PLFs of wind and solar that are higher than historical values due to improvements in technologies.

Figure 6: CUF of a wind-solar hybrid and oversized RE system



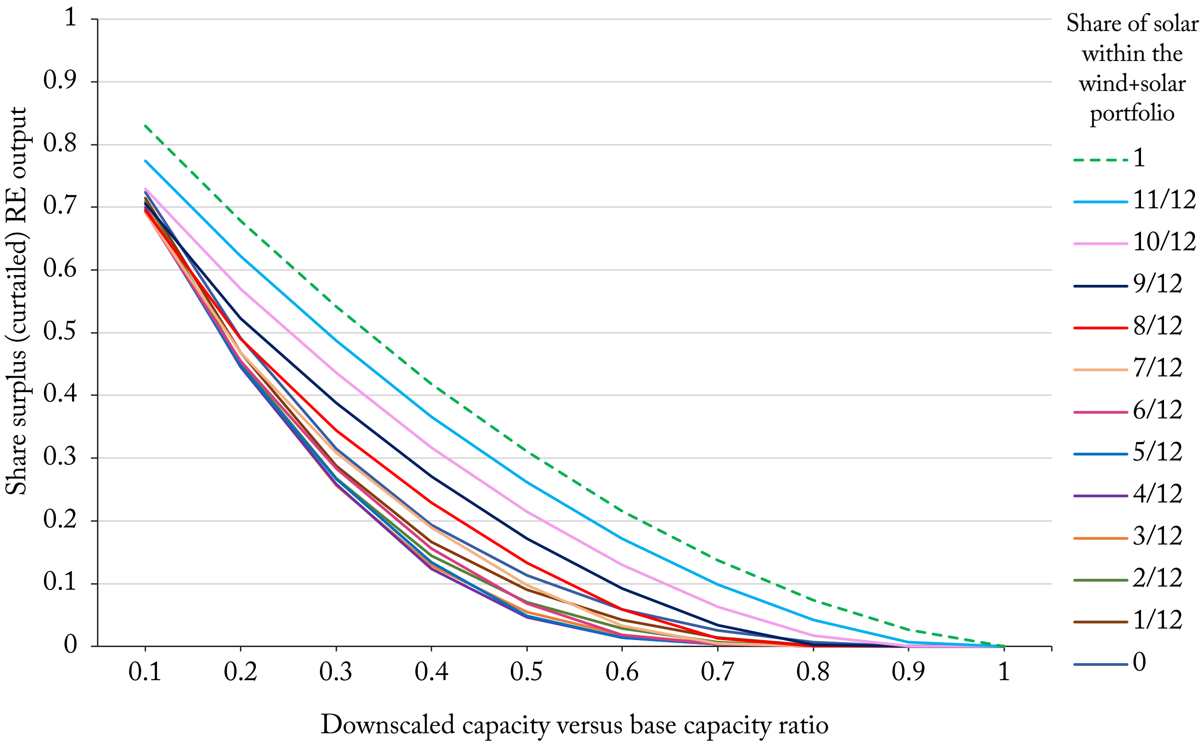
Source: Author's analysis.

Notes: This illustrative example assumes a CUF of 27% for new solar and 35% for optimally located new wind at high hub heights. This is based on 2019 wind and solar profiles captured in carbontracker.in from MERIT data.

We can see that a pure solar system (green line) does not benefit much from oversizing (moving leftward in downscaling ratio from the starting point of unity), but as we add wind to the mix, which provides complementarity, we find a sharp increase in the new (derated, or downscaled) system's CUF.

However, this higher CUF comes at a cost, stemming from occasional system output exceeding the new nameplate (downscaled) size. Adding wind also raises system costs as its levelised cost is higher than that of solar. Figure 7 shows the share of curtailment from oversizing RE. Curtailment is low until high oversizing for most blends of wind and solar except ones that are heavily solar. This is to be expected since without wind we do not get system time-of-day diversity for electricity generation.

Figure 7: RE curtailment (excess output) based on downscaled nameplate capacity



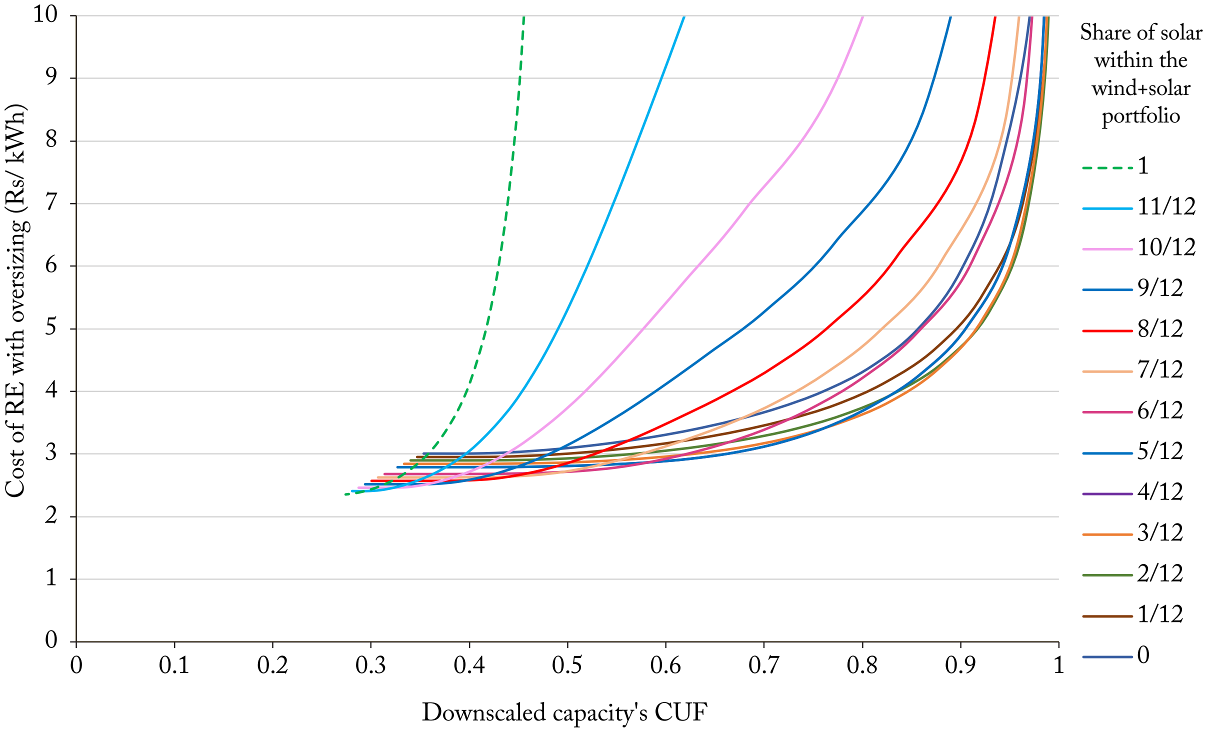
Source: Author's analysis.

Notes: Other assumptions as listed in the main text and Notes below Figure 6.

Such curtailment raises the cost of delivered RE per unit, but it is modest for a wide range of system designs where the surplus, and thus curtailment, is minimal.

Put together, these create a frontier of electricity costs (Rs/kWh) versus CUF for green hydrogen or other uses (Figure 8). It shows minimal or modest price rises for substantial increases in CUF. Not shown is the oversizing ratio (i.e., downscaling ratio) that leads to the respective costs and CUF. Solar and wind data are as per Tongia (2022) using 2019 data for illustration purposes, with assumptions translating to individual costs of 2.35 Rs/kWh and 3.01 Rs/kWh, respectively, for 2021 pricing data.

Figure 8: Frontier of RE costs versus CUF for various combinations of solar and wind and oversizing



Source: Author's analysis.

Notes: This shows how there is a trade-off between higher CUF and the higher cost of electricity (Rs/kWh). Not shown is the level of clipping from oversizing. Other assumptions as listed in the main text and Notes below Figure 6.

How much oversizing (i.e., downsizing the derated capacity) and with what ratio of wind and solar is optimal? It depends on the usage profile and the system costs for downstream usage. A complementary CSEP paper (forthcoming) examines optimal RE oversizing and wind-solar blending and the implications for green hydrogen production, integrating higher energy costs versus higher CUF overlaid with hydrogen electrolyser cost structures.

The proposed oversizing is not a novel idea per se as solar farms are already oversized at a DC panel level compared to the rated AC output because it is cost effective (and produces a flatter output with higher nameplate CUF). This paper applies that idea to an RE system with wind and solar feeding into a green use like green hydrogen production in India.[22] The numbers shown here are illustrative and based on 2019 wind and solar output data. Each year will be a bit different. The point is not to claim that a specific oversizing or wind-solar blend is optimal but that there is a strong value to these designs.[23]

One significant downside to oversizing is that it needs measurably greater RE capacity installation. For a downscaled nameplate capacity of 1.2 MW (with higher CUF), we may need 2 MW of RE investment (1 MW wind plus 1 MW solar with 50:50 blending). The fact that it costs more per unit of electricity is not the problem as we benefit from a higher CUF, but it is that India is already behind schedule in adding more RE capacity to meet ambitious targets for the grid before considering new green electricity demand for uses such as green hydrogen.

[22] Some Indian developers are already starting to deploy hybrid wind+solar systems with oversizing that allows them to headline a higher PLF (over 50% in cases), and US green hydrogen plans also appear to focus on such oversizing. One benefit they enjoy is that even the RE production enjoys government support, distinct from IRA support.

[23] A single pair of new RE plants need not have the same blending benefits as calculated, which are based on all-India data and thus have more diversity. But the broader benefits of blending still remain.

Are there other options to improve CUF with a non-carbon electricity supply?

Offshore wind has a higher CUF than onshore wind, but it also costs more. How much more? We only have projections since India is yet to build any offshore wind turbines. Anecdotal estimates are as high as 9 Rs/kWh for early deployments. Even in the long run, there are reasons the costs may be several rupees per kWh higher than in Western Europe, in part due to the geography of India (difficult continental shelves in some of the steady wind regions) plus higher costs of capital than in Western Europe. Off-shore wind's CUF is perhaps 5–10+% higher than in good locations on land,[24] but the trade-off is the per kWh costs are still estimated at several rupees higher than for onshore wind power. Nonetheless, India should still start developing offshore wind because its output could complement other RE, which adds value beyond just higher CUF. However, even if India tried hard, it would be multiple years before we have any meaningful offshore wind turbines, probably longer, due to field measurements required offshore at a microsite level, plus the time and costs associated with building a first-of-a-kind system before scaling production.

Nuclear power is also considered a clean (at least zero-carbon) source of electricity; hydrogen made from electrolysis using such power is termed pink hydrogen. While it has a high PLF, nuclear's per unit electricity costs are far higher than from VRE, estimated to be at least 6.5 Rs/kWh or higher for new builds.[25]

5.3 Can we Raise the CUF of Green Energy? Option 2: Storage, such as a Battery—Very Expensive

Batteries are an emerging and important technology for a low-carbon future. Our focus here is on the use of batteries to raise the CUF of green energy for low-carbon applications such as green hydrogen or charging EVs. Thus, we focus on grid-scale batteries for bulk storage and not on batteries for niche grid applications such as providing grid ancillary services support (e.g., frequency support or black-start capability), which are already viable today but require far less battery capacity. Considering non-grid uses, batteries are also already cost effective today for a range of EV applications.

What are the economics of grid-scale batteries in India today? We have very limited deployments to date, and so, unlike for VRE, bids are not a good indicator.

Aren't there already some bids for grid-scale batteries in India? The famous and original round-the-clock (RTC) green power tender (RTC-1) did not actually specify storage. It asked for semi-firm RE-based output with a minimum guaranteed availability. However, the winning systems did not rely on storage to guarantee higher offtake as they primarily oversized RE to provide a minimum offtake (Gambhir, Dixit, & Josey, 2020), with the norms allowing any surplus post-over-sizing to be sold in the market. RTC-2 allowed bundling with any generator (including thermal) to achieve a high CUF, with only a minimum of 51% to come from RE directly (Gulia, Thayillam, & Garg, 2021). Storage was optional.

More recent bids, on the other hand, have an explicit storage component, though some allow for a certain amount of flexibility in output. They typically only tell us a blended price for the RE with storage, which will always be cheaper than storage alone. They have high availability requirements (90–95% in most cases) but still fall short of "on-demand"; in theory, a system could be unavailable at exactly the time it is most needed but would not face any contractual penalties for this.

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[24] European wind CUFs are about 10% higher on average (in absolute terms) than in India, a figure that experts confirm remains true even for offshore wind. This is one reason many European green hydrogen plans rely heavily on wind, not to mention that Northern/Western Europe is not known for high levels of sunshine.

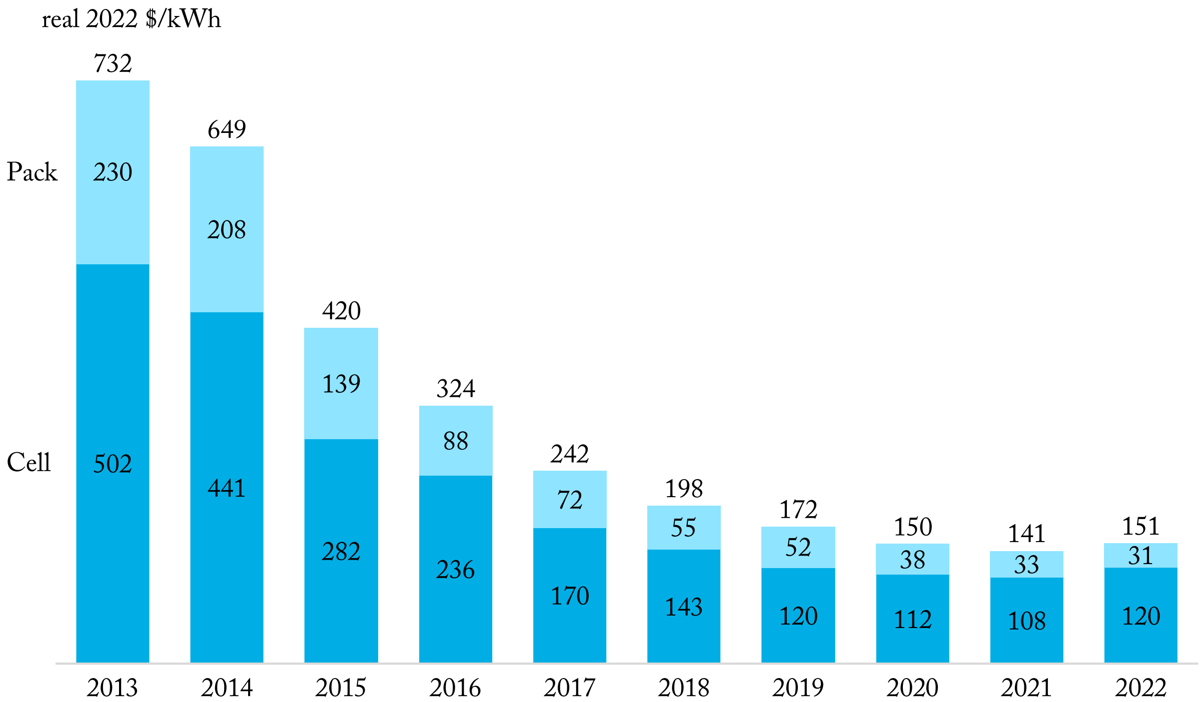
[25] CEA's *Optimal Fuel Mix* report (CEA, 2020) estimates nuclear to have a capex of Rs 19 crore/MW, compared to Rs 7.6–7.85 crore/MW for coal. That would put electricity costs close to Rs 7/kWh after factoring a modest fuel and heavy water cost (inclusive of waste disposal cost). Even such capital cost numbers are low by global standards, less than half of what the US estimates for new light water reactors (based on the US EIA (2021) *Annual Energy Outlook 2021).*

A 2022 bid by the Solar Energy Corporation of India (SECI, the PSU joint venture for scaling RE) was for just two hours of storage (250 MW and 500 MWh of capacity and energy, respectively), compared to more typical "4-hour batteries".[26] The winning bid's price was Rs 10.84 lakhs/MW/month (JSW Energy, 2022). Back calculating into US$, this translates to about 525 $/kWh capex if one assumes the battery lasts the entire 12 years, or about 400 $/kWh capex assuming cells need to be replaced partway.[27] Either way, this is not low, even after considering the small energy size (MWh to MW ratio of just two, meaning just a two-hour duration system). While costs are expected to fall over time, we can estimate where they may go based on global trends.

A leading source of information on battery prices is BloombergNEF, which publishes an annual lithium battery pricing survey that receives widespread attention. It is also often cited in a range of studies and planning documents at every level (from the Intergovernmental Panel on Climate Change to the Government of India to industrial reports to academia/think tanks).

A reported "magic figure" where battery costs become cost-competitive with internal combustion engines for vehicles is $100/kWh. Recent trends shown in Figure 9 have brought us closer and closer, excluding the 2022 figures, which registered a rise of 7% (the first rise in a decade).[28]

Figure 9: Volume-weighted average lithium-ion battery pack and cell price split, 2013–2022



Source: BloombergNEF (2022).

Notes: As per BloombergNEF, "All values in real 2022 dollars. Weighted average survey value includes 178 data points from passenger cars, buses, commercial vehicles, and stationary storage".

However, this figure does not tell the whole story. These are disproportionally automotive batteries, which are a different design than those needed for grid-scale storage. Grid batteries are designed

[26] Even four-hour batteries would not be sufficient to cover all overnight usage in India, as Tongia (2022) has shown, and instead provide maximum value for meeting peak demand.

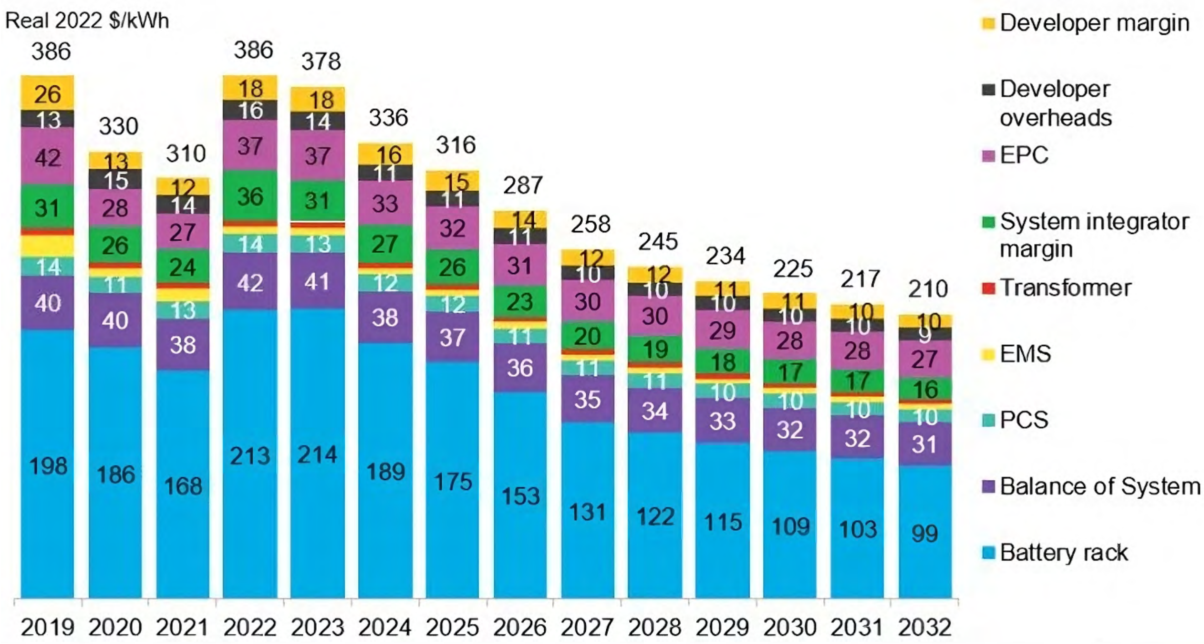
[27] This assumes 11% weighted average cost of capital (WACC) for the 12-year contract period and a foreign exchange conversion rate of 80 rupees per US$.

[28] These figures are in US$, and long-term rupee depreciation cuts into some of the cost declines. Plans to Make in India would help, but some raw materials are likely to be imported.

for multiple times higher cycling than automotive batteries, where a weekly charge and a 1,000 cycle design life with minimal degradation would last almost 20 years. Grid batteries also need an inverter; even co-located units with a hydrogen electrolyser may need an inverter if they are to interact with the grid.

If we look at a far less publicised figure for four-hour grid-scale battery costs on a usable basis, also from BloombergNEF, the costs are about 2.5 times higher (Figure 10)! Their projections through 2032 remain much higher than today's costs from automotive packs (Figure 9).

Figure 10: Capital costs for a fully installed large four-hour ac energy storage system at the beginning of life, on a useable basis



Source: BloombergNEF through Kou (2023).

Notes: As per BloombergNEF, "Excludes warranty costs, which are often paid annually rather than as part of the initial capital expenditure. These costs do not explicitly include any taxes, although due to a lack of transparency in the market, some may be unknowingly included. This excludes grid connection costs since these are very location-specific. Does not include salvage costs or project augmentation. 2019, 2020, and 2021 figures adjusted for inflation to real 2022 $".

EPC = engineering, procurement, and construction; EMS = energy management system; PCS = power conversion system.

BloombergNEF figures are close to the US National Renewable Energy Laboratory's *Annual Technology Baseline* estimates for utility storage (NREL, 2022), which are based on bottom-up technology assessments and also break down costs for different capacities (two-hour to ten-hour duration). Their 2030 projection for a four-hour battery system is just under $200/kWh; part of the difference may be how BloombergNEF normalises "usable size".

Why is there such a difference between automotive and utility-scale storage even beyond battery pack costs, which may reflect differences in chemistry and cell design? In a car, a lot of electronics and controllers may already be available, as well as a frame, but for grid storage, all these will have to be built and are reflected in the measurable overhead and margin cost components.[29]

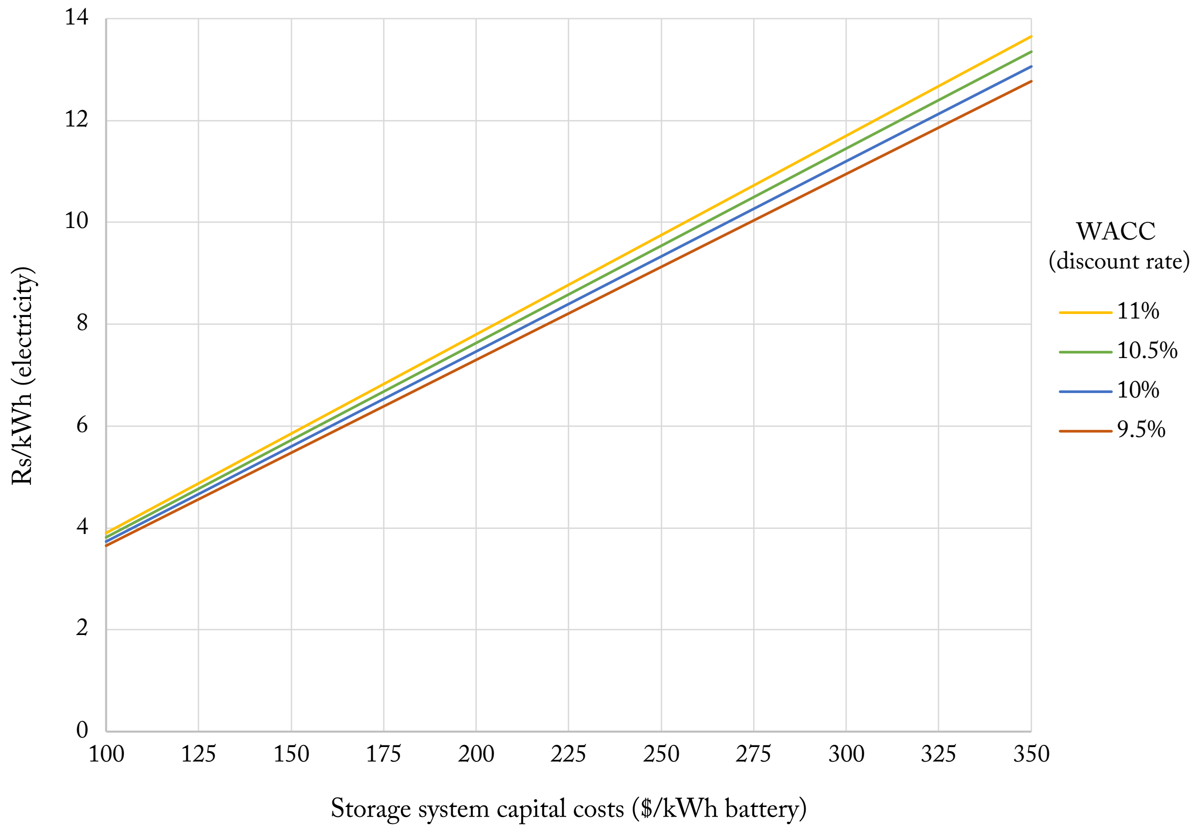
What do these capital costs mean for electricity costs with a battery? Many calculations focus on blended system (RE + storage) costs, assuming a certain size for the battery. Further, this is not only

29 Indian battery systems likely will need more active cooling, which is not just a capital cost, but a significant operating cost.

assumption driven but it is also not a static calculation, as the optimal ratio of RE to storage may vary. In the very short run, India does not need much or even any battery storage given that it can add more wind or solar as-is. In the very long run, the 35%–50% range of RE window coverage may be a useful sizing marker—i.e., for 24 hours in a day, just about one-third to half the power can come directly from RE. Adding in a buffer and seasonal variations plus battery discharge limitations implies that we would need even more storage.

Figure 11 shows the first principles calculation of the cost of electricity going through a battery under a range of optimistic or RE-favourable assumptions, including a daily full-use duty cycle, 15-year life, and only 1.5% operation and maintenance costs, combined with modest weighted average costs of capital (WACCs). This is before considering the cost of RE to charge the battery and round-trip charging-discharge (efficiency) losses.

Figure 11: Cost of storage per unit electricity



Source: Author's calculations.

Notes: These are the storage costs without the costs of charging the battery with RE, and are with favourable assumptions such as low operation and maintenance costs of 1.5%/annum, a 12-year life, Rs 80/US$ foreign exchange rate, and daily full use (95% of nameplate capacity). Four different weighted average costs of capital (WACCs) are shown, ranging from 9.5% to 11%. It would take a dramatically lower cost of capital to overcome high up-front capital costs (US$/kWh).

We can see the magic number of $100/kWh capital costs would still mean an almost 4 Rs/kWh cost of going through the battery. At the projected 2030 cost of $225/kWh for the battery system, this translates to approximately 8 Rs/kWh of electricity. Further, we have to add the RE cost, which is likely to be Rs 2.6/kWh or more, with system losses (battery efficiency losses plus transmission losses). Since the first use of RE would be to use it without storage, we do not need 100% storage. But even a favourable long-run 50% storage requirement would push 2030 prices over 6.5 Rs/kWh for the electricity.

These battery cost calculations indicate enormous implications for the role of batteries in India's grid. Contrary to popular belief, RE + storage is not cheaper than coal yet, not without a range of assumptions that may not be justifiable. The value proposition of batteries or other storage is outside the scope of this paper, and the focus remains on the higher CUF a battery could provide for green usage, which comes at a very high cost.

Compare the cost premium for going through a battery with the frontier for simply doing more optimised RE planning and design such as with hybrid RE (Figure 8). Such designs raise RE CUF far more cost-effectively than a battery. Raising the CUF measurably requires longer duration batteries—more MWh per MW of the system—which is inherently expensive. Most general grid applications get enormous value from a typical "four-hour battery", such as for a limited duration daily peak. For steady-demand applications such as green hydrogen, a four-hour battery only adds 16.6% of CUF on a daily duty-cycle basis. Ongoing CSEP studies on green power usage, especially green hydrogen production, examine such issues in more detail.

Batteries Have Value but not Necessarily for Smoothening RE Output for Green Applications

While time-shifting supply via storage is expensive, this does not mean that batteries have no value for India's grid or that India should simply wait for costs to come down. To begin with, developing manufacturing and deployment capacity takes time. Second, there is a grid value for the wider range of services batteries can provide instead of just daily time shifting of load. As Tongia's (2022) grid analysis shows, the near-term value of batteries comes from their peaker role more than from being able to end coal use. Batteries can also provide enormous value in the form of ancillary services, and they also have premium value for locations where they can be used to avoid new transmission builds or there are other considerations (such as islands and Himalayan regions).

Batteries are a nascent technology, perhaps akin to where RE was 10–15 years ago, and thus worthy of support for the benefits it offers the larger ecosystem independent of a focus on any particular use or application. Unfortunately, Indian battery tenders have been put out without adequate clarity on several policy specifications. Many plans are for batteries co-located with RE to allow the generator to have flatter or more controlled output. However, a nimbler system would also have storage capacity near consumption points, such that the same battery could service multiple electricity suppliers. The size, location, and duty cycle of any battery should be as flexible as possible, allowing the technology to offer all required services. However, the legislation still does not offer clarity on whether a battery should be treated as a consumer or a supplier of energy. Technically, because storage buys and sells power, it cannot be a standalone service, not without a license. This needs to be fixed, and a policy update is pending with the proposed Amendments to the Electricity Act, 2003, tabled in Parliament.

6. Policy Implications and Discussion

6.1 Transparency First

We need proper accounting of emissions, first from fossil fuels producing electricity and ultimately of the ecosystem of consumption (which is called Scope III emissions).[30] How green we want our green electricity (and overall energy) to be is a policy choice that is distinct from properly defining and measuring the greenness of our systems. Fuel-based average measures are somewhat easier, but

[30] Scope I emissions are those produced directly by an entity's operations, like fuel consumption when a company delivers products to consumers. Scope II emissions include those produced elsewhere for energy services directly purchased. This is primarily for electricity purchase, where power plants in the grid emit greenhouse gases. Scope III adds in emissions from the upstream and downstream production and consumption of the product.

"green power" and marginal emission measurements are complex.

A starting point for emissions measurements is the electricity grid. Today, we have average (greenhouse gas) emission factors per fuel, but we do not have good models for instantaneous and marginal emissions by fuel. CEA only lists fuel-wise (average) emissions factors, but the emissions from a particular coal power plant depend on a range of variables including its coal quality (we usually just know the quantity of coal it uses, not the energy content of the coal per plant) and plant efficiency. Newer plants using super-critical technology are inherently more efficient than older plants. Even the size of the plant matters, with larger ones being more efficient. Importantly, the efficiency of any individual plant can change based on its duty cycle; operating at a full steady load is much more efficient than part load operations with up and down cycling. All these impact emissions, but the current norm has been to do fleet-wide average accounting.

A key component of emissions accounting is linking these to the time of day, which then inherently ties to consumption patterns and the end use. The daily aggregate load profile of the grid differs from the load profile that EVs may have, which would differ from hydrogen electrolysers; differences are evident even for more traditional usage, such as for an aluminium factory.

6.2 Getting it Right Matters for More Than Just Total Emissions – Exports Will Hinge on This

A fraction of green hydrogen, perhaps a significant fraction in the medium term, will be designed for exports. This is because the premium is more likely to be absorbable by a combination of richer countries and ones that are willing to be more aggressive in early industrial process carbon mitigation.

If Indian norms are not compliant or compatible with the importing country's emissions norms, e.g., for green steel (which can be made with green hydrogen), then Indian exports would suffer. Implications could range from the product simply being disallowed to an economic penalty being placed on the product, such as through the upcoming European carbon border adjustment mechanism (CBAM).

Germany recently issued its H2Global tender, which has clarified what counts as green hydrogen/ green ammonia and asks that it must use *exclusive,* qualified RE.[31] Europe overall is looking at (phased-in) additionality requirements and stringent overall emissions (reportedly envisaged between 18 to 38 g-CO_2/MJ, which translates to between 2.16 kg-CO_2/kg-H to 4.6 kg-CO_2/kg-H) for grid-interconnected green hydrogen. Much of the blue hydrogen might not qualify (see Table 1), and the current Indian green hydrogen will most likely not qualify.

India has a strong case to make that its consequential emissions from green hydrogen as set up today are lower than in many other countries. This is because it has high RE capacity growth, and thus banking is a reasonable option given that temporary extra RE supply during certain parts of the day would not be curtailed (rather, will displace coal). In addition, India's grid is not affected by pricing signals from surplus RE yet (more on markets in a subsequent section). But this will not remain true forever. By the time India has ramped up exports of green hydrogen or green hydrogen-based products, the case will be much harder.

Do Indian norms have to match global norms? Critics fear that this is a slippery slope towards "carbon colonialism". At the global level, India needs to negotiate that its domestic emissions are properly

[31] As per Germany's Green Hydrogen/Green Ammonia tender, HPA Annex 6.1B, "Installation Generating Qualified Renewable Electricity means an individual unit or a group of units, producing electricity in one or several locations exclusively from the same or from different qualified renewable sources, excluding units producing electricity from biomass, landfill gas, sewage treatment plant gas, biogas and storage units." (European Union, 2022).

measured and conform to formal domestic norms. These need not be based on external norms but are still eligible for not just green trade but also global climate finance. And while the principles of CBAM are clear (to prevent carbon leakage), there is a need for innovative instruments that reflect historical emission differentials between the West and India to maintain Indian (and similar) exports. But simply refusing proper measurements and standards under claims of sovereignty would be counterproductive. Having a robust metric and then arguing for allowing exports based on it is more likely to succeed than refusing to have standardised measures. This would either result in blanket disallowance for products or importers applying emissions calculations that simply assume the worst.

6.3 Proper Definitions are a Subset of the Larger Need for the Right Electricity Frameworks and Instruments

Additionality is a key need for emissions accounting, but claiming additionality is more than simply measuring what generation source (like RE) grew in the grid. Significant RE growth is happening independent of aligned usage, such as in EVs or for producing green hydrogen.

With high RE growth, India's *incremental* power sector emissions in the coming decade are projected to be exceptionally small for a large country with such a low base of electricity use (and thus significant growth in demand). This is because most new capacity currently being constructed is RE. However, this does not diminish the fact that most electricity today comes from coal and is projected to remain so, at least through this decade, but that is a historical legacy.

India's primary policy focus needs to be growing and scaling RE. Improved metrics for CO_2 emissions, including time granularity, can help spur green-aligned demand, which, in the long run, can make even more RE cost effective without needing as much storage.

There has been a wide range of studies on India's grid, but these feature limited analysis of the consumption mix at a time-of-day level and its uncertainty. Many models extrapolate demand curves from today, while only a few, such as Lawrence Berkeley Lab's study by Abhyankar, Deorah, & Phadke (2021), have addressed demand shifting, such as with solar pump sets.

Any policy framework for green energy needs simplicity to enable compliance, but sometimes simplicity in measuring emissions, such as from static emissions factors, can go too far. As Ricks *et al.* (2023) note, the US "IRA statute specifies that the greenhouse gases, regulated emissions, and energy use in technologies (GREET) model, a life-cycle analysis tool developed by Argonne National Laboratory, should be used to assess the emissions intensity of all hydrogen production for the purpose of determining 45V PTC qualification" (45V being the statute or code for green hydrogen production tax credits). India lacks such models, more so public models. These are necessary for measuring the greenness of supply, especially for measuring the additionality of greenness. US NREL's Cambium project aims to build out long-run models of the US grid and changing emissions, which can quantify long-run marginal emission factors (see Appendix 2 for more information).

Accounting is only one side of the coin. The other side of high RE is incentives and instruments, i.e., pricing. India does not have time-of-day (ToD) pricing for most electricity. Traditionally, pricing was based on the sum of the components of the supply portfolio, and even policies relating to when to incentivise controllable power consumption (such as irrigation pump supply) were linked to heuristic "off-peak" periods such as at night. However, we can now add another dimension of greenness. The good news is that the cheapest new electricity (solar) is also the greenest.

Time-of-day prices are not just signals for consumers; they also influence how utilities choose fuel mixes to contract procurement in the future. Present procurement comparisons are made through the average pricing norm of levelised cost of energy (LCOE), close to the representative costs we showed calculated for coal and RE before. Levelisation helps compare values that change over time, such as due to increasing fuel costs for coal, but it ignores not just the time-of-day implications but also the incremental costs on the rest of the system.

A focus on LCOE makes solar appear much better than wind, even though wind has a higher CUF and gives an output over larger parts of the day; it is also more locationally diverse than solar. The one-dimensional measure of LCOE needs to change through system-level pricing norms.

In India, RE power enjoys a range of implicit subsidies, even if explicit subsidies are limited (households still enjoy a 30% central government capital subsidy for rooftop solar, while bulk solar procurement has no direct subsidy anymore). Implicit subsidies and support range from transmission cost waivers to cross-subsidy surcharge waivers. These will also need to be addressed as RE grows.

Limits of Paper Instruments: The Challenges and Lessons from RECs in India

Renewable energy certificates (RECs) are paper instruments designed to spur the growth of RE by creating a market mechanism for trading the “greenness” of electricity. Utilities and end users find these attractive since they just need to buy a REC to be compliant with renewable purchase obligations (RPOs) or to claim green cred. They then go about their regular business of procuring power.

RECs can enable efficiency because some locations/states/companies may inherently have more or cheaper RE, and they can sell a REC to an interested buyer. RECs enable consumers of power to turn green by buying a REC without actually generating or procuring their own RE. In this sense, RECs are like offsets that rely on surplus and deficit RE trades.

India began implementing REC trading in 2010–11 and designed separate RECs for solar and non-solar. In the early days, RE was expensive, so an end user could find value in the greenness distinct from the energy value of the supply.

However, over time, RE has become cheaper, even cheaper than conventional power. Therefore, there is no reason for a discom to buy a “green certificate” (a REC) and also buy power to meet consumer demand. Directly procuring RE provides both greenness and energy at a lower cost.

More critically, there are two major questions when we consider the relevance of RECs for “green power” *at a systems level,* such as for green hydrogen.

First, there is the issue of additionality. Unless RECs lead to more RE, they are simply changing who owns the title to such greenness.

One way that RECs can have additionality is if there is increased demand for greenness,[32] such as through higher RPO mandates. However, higher RPOs can still be met directly, except for states that have poor RE resources. Even such users can directly buy RE elsewhere, e.g., how the Delhi metro bought solar power from Madhya Pradesh’s Rewa project. In addition, there is pushback from states against centrally imposed mandates that they feel are too stringent.

The second issue is one of timeframes. Indian RECs began with a one-year validity, which was subsequently increased; the 2022 updates made them valid indefinitely until sold (CERC, 2022b).[33] There is no concept of an hourly REC (anywhere in the world that we know of), but that is what would be needed to ensure that paper instruments can jointly meet additionality and timeframe requirements. Though this could take some time to realise, it is worth moving in that direction since it gives us not just a signal for time-of-day pricing of electricity but also for time-of-day green electricity.

32 RECs are a market mechanism to determine prices, but like any price float market, it cannot set volumes. That is an outside (exogenous) decision by the government or regulators.

33 There are other complexities in the updates such as multiplier factors for different forms of RE, initially for three years, which make emissions accounting much harder.

6.4 Electricity Banking Like Today Cannot Last

How to allow "banking" of green power for consumers who self-generate RE, e.g., with behind-the-meter solar, is a contentious issue. Different states have different norms, but most levy nominal charges for banking. Banking needs to be examined using a neutral lens of accounting instead of one focused only on supporting a nascent sector. After all, if a consumer is using the grid like a battery, they need to pay for that service.

For end uses of green power such as green hydrogen, the Ministry of New and Renewable Energy (MNRE) has notified via the Green Hydrogen Mission (MNRE, 2023) "facilities for suitable banking" but does not spell out any details. It also suggests that the costs of banking will be determined by appropriate regulators or entities but would be capped.

The Indian green hydrogen norm of allowing 30 days of banking would likely result in far higher emissions than US estimates for weekly matching of RE, which found that emissions were about three-quarters as high as unrestricted emissions and worse than from grey hydrogen production (Ricks *et al.*, 2023). Not only is India's banking period (accounting time for balancing surplus and deficit electricity) longer, but its grid is also coal-heavy. To justify the use of banking, we would need to consider to what extent surplus RE in selected time periods can reduce emissions somewhere else. However, sooner rather than later, the government will need more explicit and more stringent norms for banking, both for green power overall and for green hydrogen.

The current banking policy is a dual of not having time-of-day pricing. Both result in more socialisation of true costs. Today, with near-free banking, a "green consumer" such as a producer of green hydrogen can opt for the cheapest RE, which is solar, instead of paying a bit more for wind. Solar also has a lower PLF of approximately 25% in good locations. This implies that up to 75% of the consumption would need to come from banking, much more than from the example of a hybrid wind and solar system.

Not only are there grid supply implications for banking (and more coal likely required for other time periods), but the ability to absorb the mid-day over-supply is also far worse. With such banking-driven usage still qualifying as green, and the consequent over-generation of RE in parts of the day, the country will hit the wall far sooner in its ability to handle VRE.

For instance, consider green hydrogen based on solar with a 25% CUF. If we want electrolysers to operate at 75% CUF and commensurate electricity supply, they will require banking of 50% of the supplied RE power under present Indian policy, or about two times more than the solar output used directly, so close to 2:1 banked versus direct (ignoring transmission losses). Thus, to produce five million tons of green hydrogen by 2030, we will need about 108 GW of solar,[34] out of which require 72 GW would be mid-day extra solar feeding into the grid temporarily, to be claimed back at other times via banking to raise the electrolyser CUF. This volume of solar is over 33% extra being fed into the grid compared to the independent target for additional solar in the grid through 2030, and thus further strains grid management.[35]

[34] This is purely the 47 kWh/kg-H energy basis conversion to capacity assuming a 25% PLF, and without blending or oversizing.
[35] The 33+% impact calculation is based on 280 GW total solar targeted by 2030, with about 65 GW already built.

At a minimum, national RE targets must factor in such captive solar (such as for green hydrogen production or EV charging), or else the grid would reach surplus RE far sooner. In fact, India needs far better visibility and measurement for captive and behind-the-meter RE, which complicates grid planning. While such supply helps grow RE in the short run, the system will reach VRE saturation soon, likely well before the end of the decade. In comparison, a steel plant designed for green hydrogen lasts many decades.[36]

6.5 Banking and Pricing Revisited from a Green Energy Market Perspective

Thus far, we have mainly considered the emissions aspect of banking. However, what about its economics? The only charges for RE electricity banking in India today are relatively nominal costs imposed by regulators, often a few per cent. As of 2021, a number of states had only 2% banking charges, though a few others had 5–10% banking charges, with one state having an absolute banking cost of Rs 1.5/kWh for captive consumers (Gulia, Banga, & Garg, 2021). However, true system costs of banking are far higher, something discoms are already pointing out to regulators to the extent that some restrictions or higher charges are on the anvil.

The main reason banking charges must be more than technical losses for the system relates to time-of-day economics. Using indicative range numbers, if an entity that enjoys banking facilities is producing solar at Rs 2.5/kWh and getting back power in the evening for just a few per cent charge, which might cost the utility over Rs 4/kWh if not much more at the margin (evening peak supply),[37] this cannot scale. A study by Prayas (Energy Group) (2022) on RE banking economics in Karnataka found substantial (in the order of 50 paise/kWh) costs upon the DisComs. They used power exchange prices as a marker for costs in some of the scenarios. FY21, a COVID year, had low demand and power exchange prices were much lower than we see presently. In the future, peak time period prices are likely to be even higher than "baseload" coal prices.

Ricks *et al.* (2023) purposely disallowed offsets (aka banking) in their model for green electricity for the US. With offsets, there is a significant risk that the incremental "extra" VRE displaces other RE instead.[38] It is the total RE (and thus non-RE) that matters for calculating emissions. In the short run, such VRE may be additive for India, but in the medium run (and certainly in the long run), over-supply of RE to be banked will not be additive. Any such extra solar is likely to be "too much", leading to curtailment or at least other costs.

Curtailment doesn't just mean throwing away RE, with a marginal value of zero for those units, it also changes the overall system dynamics and pricing. This is especially the case if we have power markets, where additional supply lowers equilibrium costs. While lower costs are good for consumers, with RE the risk is these can lower prices even below the levels needed to cover capital costs for new capacity, termed the "missing money" problem in literature (Borenstein, 2017). This can also reduce incentives to add more RE. Its intermittency means there will *inherently* be periods of both high ("excess") and low (even close to zero) RE output. This system pricing issue is distinct from the grid burden RE places due to its uncertainty, which necessitates firm capacity that may or may not be called into service much.

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[36] Variable RE saturation is primarily an economic cost through curtailment, but a dual challenge of high VRE is the possible inability to meet the net demand peak (typically in the evening) if there is insufficient development of complementary firm supply. This appears the most pressing problem in India's grid planning in the coming few years, more so because multiple years of "surplus coal" power plant capacity are now reaching their end. On April 19, 2023, according to CEA data in the National Power Portal, India's coal power plants had a peak generation of 90% compared to their nameplate capacity, a figure that does not reflect the fact that some plants were offline for technical reasons such as maintenance or failures. Compared to plants that were online, the peak coal plant output was almost 99%! Only a fraction of offline coal plants is likely to be able to come online simultaneously, even with heroic engineering and planning effort (and fuel supply).

[37] The fact that India may use more hydro in the evening, which has a lower price, does not change the net impact appreciably since hydro is water-limited, and the swing supply still remains coal (or even some gas).

[38] They allow for any surplus to be sold in the market for economic value, but not green power banking. India lacks sufficient market prices to reflect time of day and location-specific grid conditions.

While India does not have such power markets for most transactions yet, it has already introduced green markets such as GDAM and GTAM (green day and term ahead markets, respectively). As of now, these are nascent, with 0.45% of FY2021–22's available electricity and markets overall are a small fraction of today's overall electricity supply in India (7.38% in FY2021–22). Most of the supply (86.4%) is under power purchase agreements (PPAs),[39] which provide certainty and thus, in theory, should be a lower risk for the buyer (all calculations are based on CERC (2022a)'s Market Monitoring Report).

The use of power markets is likely to grow organically even before considering pending policy mandates for markets. India has proposals to move more supply to a market-based economic despatch (MBED) system, which would be much more prone to large downward shifts in prices from surplus RE, perhaps even down to zero.

6.6 Surplus RE and Curtailment are Looming: How do we Manage Curtailment and Ensure Additionality?

Several studies posit that curtailment of VRE can be a good thing if it can enable or lead to more green consumption at low prices. In essence, the "surplus RE" becomes a low-cost input to clean consumption. As Tongia (2022) shows, any expected surplus RE is likely to be heavily seasonal and thus would not be a good source of power for green EV charging or green hydrogen.

Curtailment is inevitable and looming, but India is yet to notify pricing and payment norms on curtailment. Most of today's policies focus on avoiding curtailment, such as the "must run" status for RE despatch.

India will enter a realm of surplus RE compared to demand for some parts of the day in a matter of a few years. This would be at a national level, and thus no amount of transmission will solve the problem. With constraints of transmission, state heterogeneity, etc., the problems will start in some regions even sooner.[40] Batteries should be optimised not for avoiding curtailment per se but rather for meeting peak demands outside the RE window. So how do we signal for and compensate for curtailment, especially in the absence of time-of-day wholesale pricing?

Curtailment is a contentious issue today, and in some cases, generators are curtailed for economic reasons. Unlike a two-part tariff for coal, where fixed costs are paid regardless of offtake, RE PPAs are single-part (there is no fuel and hence no variable cost). Therefore, if a state load control centre despatcher reduces offtake from a willing RE supplier, they save money. But the RE generator has been curtailed for no fault of theirs. There are attempts to treat such curtailment as "deemed generation." This is a work in progress.

Making power free during surplus periods can be the sharpest way to consume more during green periods. There would also be some grid stability value from higher demand during times of surplus generation. India's despatch systems and consumer pricing are not yet set up for that. A helpful step would be non-market systems such as bilateral incentive schemes focusing on bulk consumers.

Ultimately, if we do have to curtail RE, how should (green) generators be paid for this?

Linked to figuring out the price or value of curtailment, there is the question of who (which generator) we curtail. To clarify, we are talking about the future where we cannot absorb the RE because coal cannot back down lower. We cannot use marginal cost savings to determine a "reverse merit order" stack for curtailment since all RE has zero marginal costs. Ideally, we need a mechanism

[39] The balance is from other short-term transactions, including bilateral sales between discoms and power from traders. Note that these calculations are based on overall electricity available, which is lower than the gross generation of the system, meaning before auxiliary (in-plant) consumption, a norm CERC follows based on CEA methodologies.

[40] Sufficient transmission for long-distance delivery of RE is an expensive option, in part because such lines would have a low CUF. But without such infrastructure India would face "surplus RE" and thus curtailment sooner than based on aggregate national electricity demand.

to curtail RE from the location and maximise grid efficiency. In parallel, we should have a financial instrument for socialising this such that no single RE supplier bears the brunt alone.

We also need proper metrics for curtailment. As Tongia (2018b) recommended, India needs a system of declaring and categorising curtailment based on the dimensions of cause (technical versus economic) and location (last-mile, local, or regional/national), like what California Independent System Operator (ISO) follows. Compensation norms could be standardised accordingly.[41]

If we consider curtailment along the lenses of the paper, the framing of RE additionality is vital to understanding the link to emissions. As soon as we are in the realm of system-level technical curtailment, we lose additionality claims from more RE supply under consequential emissions analysis like the Kochi airport would claim. If we grow demand during periods of RE curtailment, it helps *not by lowering emissions but by increasing the production of goods and services without further emissions*. Further, if we can *shift* demand from non-curtailment to RE-curtailment periods, and thus reduce fossil fuel usage, we would lower emissions. Shifting demand and enabling more RE without curtailment should thus be the objectives of policies and frameworks.

Summary: Why Electricity Banking is an Issue for Truly Green Power for Green Applications

Whether banking "green electricity" is appropriate for decarbonisation depends primarily on whether the over-generation of RE in some time periods can compensate for the under-generation of RE in other time periods, e.g., overnight, where swing supply is likely to come from coal power in the foreseeable future. For reference, India's present green hydrogen norms allow for 30-day banking of RE banking with a discom.

In the short run, banking *might* be low or even zero-carbon under a consequential emissions calculation framework, but only with a range of assumptions. However, banking cannot be zero-carbon if we use strict apportionments using attributional emissions calculations. Even if we calculate banking as low or zero emissions in the short run, there are multiple reasons why it will not scale and is not an appropriate policy:

1) **Displacing coal through over-supply of RE only applies when we do not have surplus RE (in parts of the day).** After this point, RE generation will be curtailed (thrown away) or require expensive storage. Adding more RE supply in those time periods will not reduce emissions via displacement.

2) India's RE is disproportionally solar, which is relatively time-coincident (especially compared to wind, which is more spread out across the day but is also very seasonal). Coupled with the high use of coal, which has technical limitations on running part-load operations, **the "surplus RE" scenario is only a few years away.** If we want a steady supply (such as for an airport or data centre), direct solar will be able to meet only 25% of the demand with 75% being routed through banking. This strains grid management and the volumes injected mid-day to be banked would be substantial. For example, a 5 MT green hydrogen 2030 target would add extra mid-day solar, equalling more than a third of the planned grid solar growth through 2030.

3) Given India's ambitious 2030 RE targets, **a significant amount of RE is being built anyway,** so the additionality claim is a challenge. Stated another way, if the end user (such as the "100% solar" Kochi airport or a green hydrogen plant) did not have oversized solar (with temporary surpluses to be banked), someone else would have built such solar. Such solar would grow as long as there is incremental electricity demand matching the incremental output.

[41] A complementary recommendation is to move grid pricing towards locational marginal pricing (LMP) that reflects both the time-of-day and spatial conditions of the grid.

4) **To be low carbon even in the short run, we need an RE-coincident other consumer (of the over-supplied and banked RE) *and* a 1:1 displacement of coal.** Even a 1% gap in displacing coal would mean high emissions, given that coal is close to 1,000 g-CO2/kWh, to the point this would not comply with US IRA norms for full green hydrogen PTC credits (which only allow for <0.45 kg-CO2/kg-H, which is less than 10 g-CO2/kWh for electricity). Such gaps in displacing coal could occur due to curtailment but also because of local grid congestion issues or unplanned events.

5) Even if everything works as planned, **the incremental "green load" would not reduce coal emissions; rather, it will only avoid the growth of emissions.** To rephrase, the example Kochi airport requires someone else to use the mid-day excess solar, *but both the airport and the other user cannot simultaneously be green*. Let us consider the case where the other user's demand purely coincides with solar output. Then, they would be accounted as non-green if the airport claimed that its power source is fully green. This is one reason attributional emissions cannot be based on individual claims but must be done at a systems level.

6) The economics of banking are also problematic for several reasons. VRE is very inexpensive, but if banking requires the utility to balance RE with peak coal (or other peaking supply), that is much more expensive. **Most of the present banking norms do not charge for time-of-day differentials**—they mainly cover technical losses of going in and out of the system.

7) **Storage is expensive for smoothening out RE's output, but oversizing RE can be cost effective,** especially when combined with hybrid wind and solar designs. The downside to oversizing is that it requires even more RE capacity, but we are already behind schedule in installing enough RE to meet our ambitious grid expansion needs. To accelerate RE growth sustainably, India needs to move beyond simple LCOE (levelised cost of energy) pricing norms that ignore issues such as time-of-day, predictability, and location, and also do not factor in duty cycles.

8) **The economic impact of higher RE supply (especially more solar supply) would be exacerbated under market mechanisms of pricing energy.** Even before the point of absolute surplus RE generation, we may have over-supply due to grid constraints, coal power plant flexibility limitations, and other reasons. This would mean not just lower electricity prices for part of the day, but even possibly negative electricity prices under market frameworks. This not only hurts the economics of banking, but it also creates what may appear to be cheap power for users but is also a signal that diminishes the value of such RE, dampening future investments.

9) **Definitions of what is "green" may be driven by end users, especially for the export of green hydrogen or green ammonia,** and there are significant risks that banking-based green products may not qualify. Europe will likely notify norms and penalise imports through its upcoming carbon border adjustment mechanism (CBAM) tariffs.

10) **In the worst case, RE banking that relies on coal-based supply for other periods would raise emissions.** This would be the case independent of when we have surplus RE and could happen when there is no *net* additionality of green supply (factoring in the growth of RE happening anyway in the grid, mostly as VRE).

6.7 The Road Ahead: More RE, Better Accounting, and Better Signalling

Summary of Policy Recommendations

1) *Correctly measure and define "green power."* This can be through attributional or consequential emissions frameworks, but both require transparency and systems-level accounting. This also requires emissions models for the grid that factor in the evolution of the grid and time-of-day (and seasonality) impacts. Current frameworks for discom-delivered "green power" are predominantly an accounting label only—if a utility end consumer proclaims that it is green, then someone else must become less green.

2) *For genuinely green power supply, we need (1) additionality; (2) deliverability; (3) timeliness (e.g., hourly matching) of RE (or other carbon-free supply).* Put together, this means moving towards no banking from a "green" perspective. This is especially the case for the production of green hydrogen. To the extent RE generators want to bank power, this must incorporate system-level accounting and be charged for—they are essentially treating the grid like a battery.

3) *Signal the state of the grid from a pricing perspective.* This applies to both wholesale generators and retail consumers. Move away from LCOE measures for power supply and instead focus on system-level pricing, which inherently includes time-of-day, transmission, and alternate generator implications. Another tool is planning for net demand, i.e., system demand after subtracting the contribution from VRE. Such measures will give an impetus for load shifting and the development of storage solutions.

4) *Account for the capacity and generation (including time-of-day) of behind-the-meter and captive RE.* This is critical for optimal grid planning and for discom tariffs.

5) *Devise policies for measuring, optimising (who, where to curtail), and paying for curtailment of "surplus RE".*

6) *Incentivise future demand to align with maximum RE periods.* Time-of-day pricing is one tool. However, a holistic approach will also factor in capital investment implications, grid congestion issues (local and transmission), and the potential for new business or regulatory models (such as edge-based and peer-to-peer supply).

This paper highlighted the complexities of green supply and green consumption. More RE is inevitable and welcome. Better accounting and signalling (such as time-of-day and congestion pricing) can help grow RE at lower overall system costs.

Part of better signalling is ensuring transparency in assumptions and setting correspondingly realistic targets. KPMG (2022) recently presented an analysis of green hydrogen opportunities in India to the Asian Development Bank. The analysis envisaged 65% CUF for the electrolyser *without banking* in 2022, rising to 70% by 2030. It is unclear what methodology they adopted to achieve this while still maintaining green additionality. With proper accounting, we would have lower RE CUFs and thus more expensive truly green hydrogen.

India's grid is decarbonising, which is a good trend; this is where most policy focus should be. Green-aligned demand is another primary policy need. However, we need rigorous and formal accounting of emissions. This is important not because other countries have said so but because India can independently choose suitable instruments to facilitate even greener solutions, ranging from pro-rated supplier benefits (such as the US IRA framework), viability gap funding, and green offtake requirements. India is doing well on the RE front and poised to grow green hydrogen. To do it right, it must ensure the definition of green power is more than virtue signalling or only giving directionality. Else, it risks double-counting or, worse, greenwashing.

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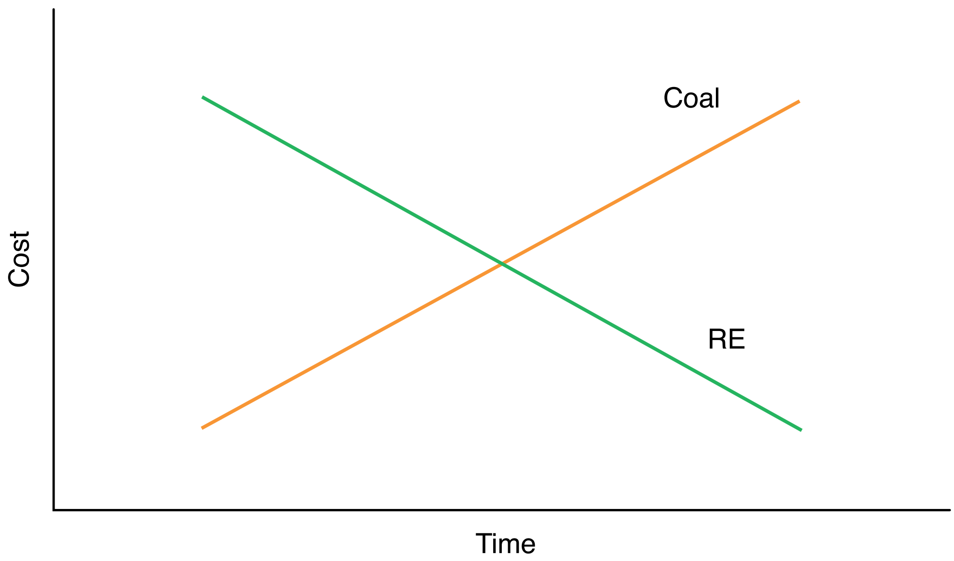
9. Appendix 1: Competition Between RE and Coal—Not a Simple Crossover

(This section draws heavily from Tongia (2018a)'s paper, "Renewable Energy 'versus' coal in India – A false framing as both have a role to play")

Traditional and popular framings for comparing RE and coal involve rising coal power costs over time and declining RE costs. These costs cross over, as shown in Figure 12. It is a separate discussion whether this crossover has already happened or is imminent.

Figure 12: Generic (typical) cost comparison of coal and RE



Source: Tongia (2018a).

This simplified framing turns out to be incomplete when we recognise several factors of importance, including: (a) Are we considering new builds or existing builds? (b) Where are these located? (c) What time of day is being considered?

Putting these together, Tongia (2018a) found competition to be more like a ladder, with each step covering different aspects of RE's competitiveness. The steps are (Figure 13):

1) Avoid new coal being built opportunistically (no storage)

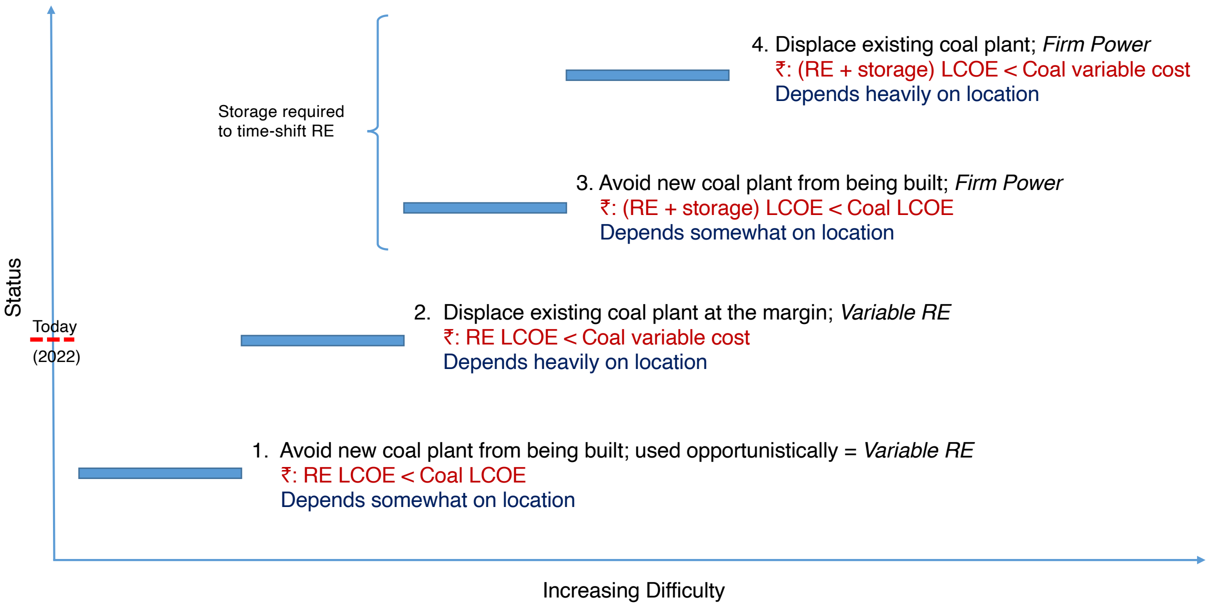
2) Displace existing coal plants at the margin

3) Avoid new coal being built (with storage = firm power)

4) Displace existing coal plants (with storage = firm power)

All of these would have sub-steps based on location. For instance, the easier coal to displace is far from the mines, which has expensive transportation.

Figure 13: Ladder of competitiveness for renewable energy versus coal



Source: Tongia (2018a).

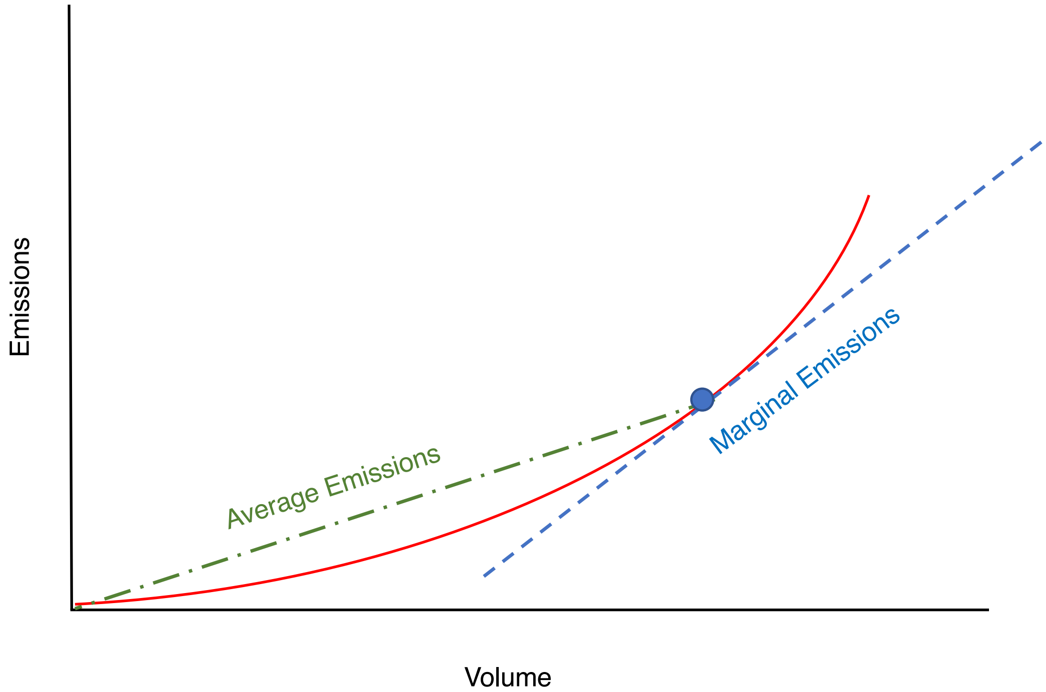
As of now, RE (especially solar) has a lower total cost than the fuel (variable) cost of many coal plants, more so ones that are away from the pithead (mine-mouth). This is also visible in Figure 3, where we see coal output mid-day dipping below the morning and evening periods.

10. Appendix 2: Measuring Emissions—Marginal, Average, and Alternatives

Intuitively, we want more consumption that could be met by more green supply, but as of now, India lacks such signalling, e.g., time-of-day pricing. How do we measure the impacts of proposed policies? Attributional versus consequential emissions are two techniques discussed in the main text but the latter is very hard to measure, not without a full system view.

A hypothetical merit order supply curve for a country has rising emissions with rising production since RE comes first in the stack. If we ignore India's limited use of gas, which has lower emissions than coal but is also more expensive, then such a stacking implies that the average emissions will inherently be lower than marginal emissions (assuming no surplus RE), as seen in Figure 14.

Figure 14: Generalised emissions curves



Source: Author's synthesis from various sources.

Notes: This is a general marginal emissions curve with monotonically rising emissions with volume. Electricity supply curves are often similar, starting with RE/Nuclear/hydro as the initial sources of supply and moving up to fossil fuels. In India, gas is more expensive than coal, and thus the curve is not exactly similar, but gas is very small in volume, and hence the general trends are similar. This also assumes no RE curtailment.

The basics of grid despatch also tell us that the short-run marginal emissions will always be higher since incremental demand always needs incremental supply, and the swing producer should never be renewables, as RE has zero marginal cost and should come first, assuming no curtailment.

One suggestion has been to use long-run marginal emissions rates (LRMER), which take into account the evolution of the grid (Gagnon & Cole, 2022). But such evolution also needs to consider load shape changes and is, thus, not easy.

Even if one has grid models, one must be cautious in teasing apart emissions. Using an optimisation model calculating optimal supply mix for a given demand, one cannot simultaneously use that analysis for back-calculating marginal emissions or emissions linked to a specific end use (recall the example given of adding an extra EV after 100 EVs to the demand: should all the incremental emissions accrue to the last user?) For example, CEA has projections for India's grid in 2032 and an optimal supply mix, which must embed some level of EV use and charging on the demand side. In such a case, the model can tell us the system's *average* emissions but not the *marginal* emissions from the EVs. To calculate the LRMER, we must combine marginal emissions analysis, e.g., by time-of-day, with how the grid would have evolved with versus without EVs. This is possible but not yet being done in most analyses.

Scale is also an important criterion for measuring change. If I buy an EV, it will not change the much larger grid significantly. But am I consistently charging my EV for ten years in a predictable pattern? Ideally mid-day? Are there thousands or millions of such EVs joining me? What happens if we have a large fleet of EVs that charges simultaneously (and such a time need not be mid-day)? We need grid models designed for multiple scenarios before we can make any claims about knowing the emissions from EVs. The only answer we can easily get is the short-run marginal emissions or the per-time block average emissions. A complementary CSEP paper is working on these aspects.

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