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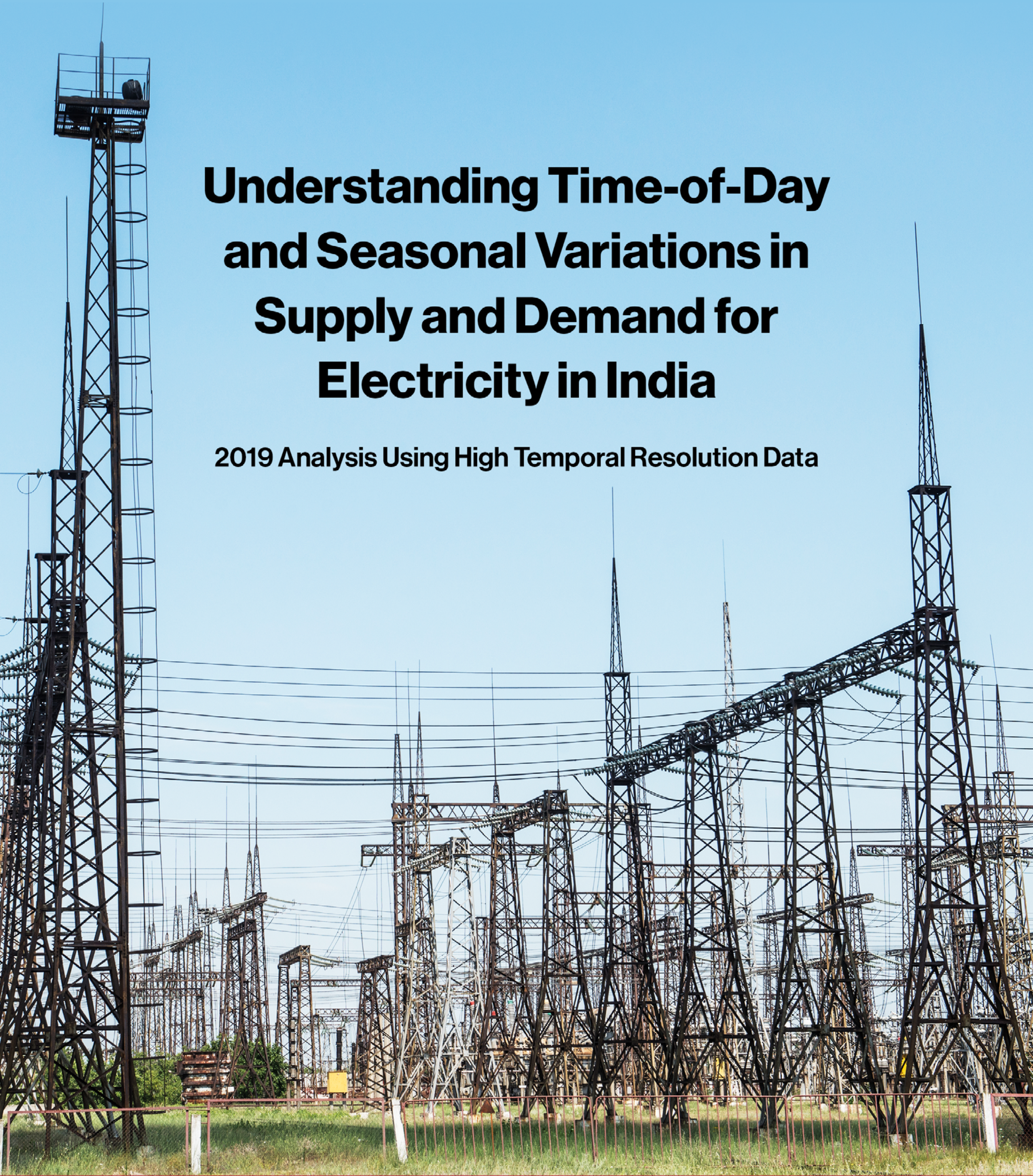

Understanding Time-of-Day and Seasonal Variations in Supply and Demand for Electricity in India

2019 Analysis Using High Temporal Resolution Data

RAHUL TONGIA AND AARUSHI DAVE (With UTKARSH DALAL)

Centre for Social and Economic Progress (CSEP)
CSEP Research Foundation
6, Dr Jose P. Rizal Marg, Chanakyapuri,
New Delhi - 110021, India

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Understanding Time-of-Day and Seasonal Variations in Supply and Demand for Electricity in India

2019 Analysis Using High Temporal Resolution Data

Rahul Tongia
Senior Fellow,
Centre for Social and Economic Progress,
New Delhi, India

Aarushi Dave
Research Analyst,
Centre for Social and Economic Progress,
New Delhi, India

Utkarsh Dalal*
Centre for Social and Economic Progress,
New Delhi, India

*Former Data Scientist consultant (January 2019 to January 2020)

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Abstract

India's electricity grid is moving from one dominated by coal to one where renewable energy (RE) will dominate supply, especially wind and solar. By 2030, the target is to triple non-fossil sources of power to 500 gigawatts (GW) of capacity. Wind and solar sources are intermittent, and given a power grid needs to balance supply to meet demand at all points in time, this raises immense challenges for planning and operations.

This paper studies the impacts of times-of-day and seasons on the different types of fuels for generation electricity, their output ramp (swing up or down) rates, daily swings between maximum and minimum output, and relative contributions of each fuel type. It also covers net demand (total demand excluding RE) separately to highlight RE's interplay with other supply sources.

We focus on calendar year 2019, which was the last year before the impact of the COVID-19 pandemic. We analyse data at 5- and 15-minute resolutions not just to understand granular grid-balance requirements but also examine ramping requirements. The larger policy objective remains improving the integration of more variable renewable energy (VRE) sources into the electricity grid and cost-effectively balancing different fuel types during specific times and/or seasons.

A key insight is that the average numbers (e.g., for correlation) are misleading and one needs granular data to consider "worst case" time periods for which we need adequate and appropriate supply. We also find that RE places greater burden on the rest of the grid in terms of ramping requirements, measured through net demand, which is the remaining demand after subtracting variable RE.

Glossary/Abbreviations

Term	Definition
Ancillary Services	Services not covered by energy provision (kilo-watt per hour or kWh) to support efficient operation of the grid and facilitate the transmission and distribution of electricity. These functions extend beyond the core generation and transmission functions of the grid, and focus on enhancing grid security and stability. These can include frequency support, ramping, black-start capability, etc.
Curtailment	The act of not using a renewable energy (RE) source output for preserving supply and demand balance in the power system; in essence, throwing it away because RE supply exceeds demand. Firm sources where there isn't a phenomenon of use-it-or-lose-it are instead "backed down".
(Coal) Flexing	Operation of coal power plants in a flexible mode, based on changes in grid conditions (supply/demand balancing), i.e. in a part load manner and/or with high ramping. There is a technical limit for coal flexing compared to the nameplate capacity, and an efficiency penalty for operating in flex mode.
Demand-Side Management (DSM)	A method of improved balancing of the grid through the demand side where consumers can consume energy more efficiently. In addition to being a one-time change (like buying an efficient air-conditioner or light bulb) this can be a dynamic process in response to signals, which is termed demand response.
Dispatchable Energy Sources	Sources of electric power that can be dispatched (called or controlled) based on the demands of the electricity grid. Also called firm power.
Distributed Energy Resources (DERs)	Small, modular energy generation and storage technologies that provide electric capacity or energy where you need it, producing under 10 megawatts (MW) usually. They can be sized to meet specific needs as per the site, with connections to the local power grid or standalone applications. (As defined by the US' National Renewable Energy Laboratory [NREL]).
Economic Dispatch	Same as Merit Order dispatch (see below)
Flexibility	The flexibility of a power system is the extent to which a power system can modify electricity production or consumption in response to variability, expected or otherwise (As defined by the International Energy Agency [IEA]).
Levelised Cost of Electricity (LCOE)	A present value calculation of average cost of electricity over the lifetime of a supply source, based on discounting finance and operating costs as well as the output over time. It is used to compare different sources of energy production whose outputs and costs may change over time.
Load Duration Curve	A plot of the load or other characteristic and time where the x-axis represents time, stacked in decreasing order of magnitude across the time-period.

Term	Definition
Merit Order	Order in which generating plants are called by the grid operators with changes in demand, based on the price of the electricity produced. Also, the order in which demand bids or supply offers are made for selling electricity.
Net Demand	Total electricity demand at the grid level, excluding Renewable Energy (RE) which is treated as negative demand.
National Load Dispatch Centre (NLDC)	NLDC —the national aggregation of smaller (regional and/or state) electricity grids—is the level of national supply and demand used in this study.
Peaker	An energy source designed to meet peak demand, the output of which can be increased (or decreased) to meet high-ramping requirements from the grid. These are typically designed to operate infrequently.
Power Purchase Agreement (PPA)	A contract between the electric power generator and a customer (could be a consumer or a trader), which defines all the terms of selling electricity. This comprises of all commercial terms such as duration of contract, payment terms, schedule for delivery of electricity, terms of non-compliance etc.
Ramp Rate	The rate at which a generator can increase/decrease, i.e., ramp up/down its generation. It can be expressed either as a percentage (of unit rating) per time block, or in absolute terms (e.g., MW/minute).
Renewable Energy (RE) components (applicable for this study)	As per Government of India historical nomenclature, RE comprises small hydro power, wind power, bio-power (biomass power/co-gen and waste-to-energy) and solar power. Newer definitions of RE include traditional hydropower as well.
Summation Supply	Total generation of electricity at the national grid level or busbar level, i.e., post auxiliary consumption. In contrast, *demand met* as measured by the Government of India's portal 'Merit Order Dispatch of Electricity for Rejuvenation of Income and Transportation' (MERIT), and NLDC, is the summation of state demands for power, which are thus the combination of supply within state plus power delivered to the state boundaries.
Time-of-Day	A term used to indicate different grid conditions by time in a day (and potentially tariff structures).
Variable Renewable Energy (VRE) sources	Generation of RE in a variable or intermittent manner, typically based on wind or sunshine conditions. These sources are, by definition, not dispatchable, meaning their potential output isn't a function of demand.

Executive Summary

The electricity grid requires a constant real-time balance between demand and supply, and different fuels aim to meet this mix. Traditionally, the Indian grid has relied heavily on fossil fuels. However, there are plans to dramatically scale up renewable energy (RE) supply. The prime minister announced at COP26 in Glasgow that the ambition would be for 500 GW of non-fossil fuel capacity, most of which would be based on wind and solar.[1] This represents a major shift from the grid of the past where three-quarters of the energy came from coal.

This paper presents a descriptive analysis of how the Indian grid performed in 2019, the last calendar year prior to COVID-19 effects, using high-resolution (5- or 15-minute) data on supply mix to meet demand at the national level. These are compiled and displayed at CSEP's portal carbontracker.in. In the paper we apply small corrections for missing/outlier data.

In this study, the focus is on understanding the relative contributions of different fuels, the correlations between demand (load met) and supply options, swings in supply (calculated as ramp rates, or rate of change of output), and limits on future performance under an anticipated high-RE future. While these appear to be technical issues, these have profound implications for choosing an "optimal" fuel mix that enables lowest cost secure supply.

At a descriptive analysis level, as expected, we find that installed capacities by fuel type aren't direct explainers for generation by fuel type. The Plant Load Factor (PLF; also known as Capacity Utilisation Factor, or CUF), for RE is low, and the PLFs of coal and nuclear are high. Hydropower is in between, but turns out to be heavily seasonal in output and value. It also performs a strong role as a 'peaker' (limited hours of high output correlated with high demand).

Total electricity demand is highest in June and July, with a second peak around September as the monsoon concludes. Thermal generation is relatively flat over the year, but rises slightly between January and June, after which it drops. This drop is offset by rising RE, and subsequently, rising hydro. During and post-monsoon, hydro reduces its daily swings and service as a peaker, turning closer to "must run" status for a few weeks. While gas does have some peaker effects, its output is relatively low throughout the year.

We find it particularly illuminating to not just examine the averages or moving averages, but also study daily swings. We find the daily demand is higher pre-monsoon, and this is driven more by an increase in the minimum per day (the daily low) rather than an increase in the daily high. The fact that most of this increase in the base (the daily low) happens during the night suggests the impact of residential air-conditioning during the summer.

Importantly, we find that national average statistics across the year are incomplete, and breaking up the data into seasons and times-of-day buckets or clusters show sharply different correlations and ramp rates than the annual average.

A crucial question becomes: how are changes in demand satisfied across fuel types? While all fuel types are correlated with demand, renewables are less correlated than thermal (coal) or gas. This spread is even starker when we consider seasonality and times of day. More important than simple correlation between demand and any particular supply is correlation for change in demand with change in supply, or delta (Δ) demand versus Δ supply. For this statistic, thermal (coal) offers the greatest correlation, followed by hydro.

If we consider ramping requirements, measured by rate of change of a supply option, we find that the percentage ramp rates differ from absolute ramping (MW/minute). This is because of the

[1] The 26th summit of nations (also referred to as the Conference of Parties or COP) that signed the United Nations Framework Convention on Climate Change (UNFCCC) treaty in 1994.

vastly different base sizes. Gas can ramp faster than coal (on a percentage ramping basis), but the total ramping contribution from coal is much higher as the output of gas is more than an order of magnitude lower than coal on average. Hydro shows strong ramp rates, but the effect is minimised during periods of steady or high hydro output (end of and post-monsoon, when hydro becomes closer to "must run" than operating as a peaker).

Renewable energy is cost-effective, but cannot meet all demand, at least not without storage, which is very expensive at present. Renewable energy targets are already in place, and RE dominates investment in generation capacity. An important question that arises is, what happens to the system overall as RE grows? We know that RE is seasonal (especially wind) and has a high diurnal pattern (especially solar). This means that as RE grows, there will be greater burden on the rest of the system, especially in terms of an alternative supply needed to balance the grid, including its daily ramping requirements. Given the low PLF of RE, we would still need "something else" (assuming no battery), but such a supply option would face lower PLF because during parts of the day or year RE suffices. Such "backing down" of alternative supply makes alternative sources more expensive than they would be if they ran to the maximum capability without RE in the mix.

An important measure of the impact of RE on the rest of the system is when we consider the concept of "net demand", i.e., demand to be met by firm sources after removing demand met by variable RE. We find that the ramping requirements upon other (non-RE) supplies is higher when we consider net demand compared to demand. This means if RE grows and supplies output proportional to 2019 output, then higher RE will place a greater burden on the rest of the grid for ramping and balancing. Renewable energy is also challenging given it can have very low output at periods of high net demand, especially post-monsoon evenings.

Daily minimum and maximum data are important and tell us the value of peak load management. Managing the peak is important since, by definition, peak power (operating a few hours per day or even season) is expensive compared to power that is used consistently over more of the year. Controlling the peak is also important for other reasons we investigate. Given net demand peaks in the evening (much of which is met from coal) reducing this peak is critical to coal usage because of the limitations on coal power plant usage. A coal plant operating at full load in the evening cannot be switched off easily or even lower its output below a threshold easily in response to high solar output. In such cases, we may have surplus RE that needs to be thrown away (aka "curtailed"). As Tongia (2022) shows in a grid modelling study for 2030 that will be a reason for high RE surplus (and thus curtailment) in the future.

The present study uses detailed data from a single year and is national in its scope. For detailed modelling and planning for managing a high RE future, we need high time (and location) resolution data on demand as well as supply, including variable RE. It's entirely possible that load profiles may change over time. While coinciding demand with RE (as through load shifting) helps reduce surplus RE, e.g., through the rise of solar irrigation pump-sets, this doesn't solve the problem of meeting net demand, which peaks in the evening. Storage, or an alternative peaker, would be required to meet the evening peak. To incentivise proper demand management with the right type of supply, both retail and wholesale power should reflect grid conditions through time-of-day pricing. This is missing for about 90% of India's power—only a small fraction is handled through power exchange markets.

Ultimately, as RE's share rises in the grid, India will need high-ramping and balancing forms of supply. These sources may not run frequently, and thus will be more expensive than average, but their value is higher. As this paper shows, if RE creates more burden on the rest of the system, including ramping, then those other generators need to be compensated for such services. Unfortunately, majority of the planning and payments today are linked only to energy services, that too average energy (levelised cost of energy [LCOE]). Instead, capacity value should be considered, particularly for energy sources operating as peakers. This needs to be an area of active analysis and policy focus. In particular, we need a portfolio system of pricing supply options, instead of today's focus on LCOE. By focusing on a portfolio model of pricing, we would capture system-level costs (e.g., due to transmission or backing down of coal).

Study Motivation and Background

Rising Uncertainty and Variability in the Grid

Given India's low base of electricity consumption per capita (about one-third the world average) according to the Ministry of Power (PIB, 2022) and high gross domestic product (GDP) growth rate, electricity demand is growing rapidly, at over 5% per annum, varying by year. In addition to overall growth, there have been shifts over time in how the growth in demand has been met.

India's electricity grid grew from 1,713 MW installed capacity in 1950 to around 370 GW (excluding captive capacity) as of March 31, 2020 (CEA, 2021). Further, the Central Electricity Authority (CEA) projects the installed capacity to rise to around 844 GW by 2030, including battery energy storage systems (CEA, 2020a). Some of this dramatic rise in capacity will be due to growth of RE, which operates at low PLF or average outputs, and hence you need more capacity for the same energy output.

The expansion of the electricity grid between 1950 and 2019 was largely propelled by thermal capacity, with spurts of hydropower growth in the earlier years. However, the growth in installed capacity and electricity generation in the forthcoming decades is expected to be driven by cleaner energy sources, such as wind energy, solar energy, nuclear energy, renewed hydro energy and battery energy storage systems.[2] This shift will create challenges from planning and operations perspectives. The most obvious issue is that wind and solar are both intermittent and variable. More subtle is the presence of both variability (somewhat predictable, like no solar output at night) with stochasticity (more rapid, e.g., sudden cloud covers or dips in wind) in output from variable RE (VRE) like wind and solar.[3]

Some of the trends and challenges that the Indian electricity grid can expect in the near future and as part of its energy transition:

1. *Overall rising demand for electricity across different sectors*, but with asymmetric growth across sectors. Which sector grows faster will have implications on demand time-of-day and utility finances, since distribution companies (discoms) have differential prices for different consumer categories (with prices set by regulators);
2. *Change in demand profiles, supply mix, and CUF of infrastructure.* As RE grows, coal's PLF will fall;
3. *Rise of clean energy technologies,* which are often not just variable but also distributed (compared to more traditional centralised generation, such as from coal plants). Clean energy solutions extend to electric vehicles (EVs) and use of storage technologies including batteries;
4. *Expansion of transmission and distribution networks,* not just to meet rising demand but also based on clean energy transitions, e.g., the need for long-distance but low PLF transmission to transfer RE across states, or the need for more local intelligence to handle consumer-based feeding in of power like from rooftop solar;

[2] Historically, the main form of grid-scale energy storage worldwide was through pumped hydro systems, but for various reasons, these have found limited deployment in India thus far. Batteries are highly responsive and can charge or discharge on-demand, but are projected to remain expensive through 2030 (Tongia 2022)

[3] Solar power also lacks inertia, a useful quality of large rotating turbines and generators that helps keep the grid stable. However, such issues and millisecond grid stability and transient power flow concerns are outside the scope of this analysis.

5. *Greater pressure on grid balancing and ancillary services* (services to keep the grid stable, including frequency support, ramping, etc.). These are services whose value cannot be measured in terms of energy (Rs/kWh) alone. A complementary need is for all generation to be more nimble and able to operate at part load and in flexible modes, especially coal supply;
6. *Need for consumer engagement to improve demand side management.* The old grid had varying demand met by over-engineering firm demand. Now, supply (RE) is also variable, and instead of over-engineering alternatives, one can control or shift demand to align through a combination of price signals (like time-of-day pricing) or control signals (directly controlling loads).
7. *Pressures upon distribution companies (discoms) to reduce high losses*, both financial and technical. A flip side of this is the plan for a greater role of wholesale markets to enable efficiency, which will change the relationship between suppliers and consumers from today's system dominated by predictable and typically time-of-day-agnostic bilateral contracts (power purchase agreements). However, discom planning will get harder with distributed generation which is often "behind the meter" and owned by consumers.

A common thread between almost all of these trends and consequent challenges is the aspect of *uncertainty*, which goes well beyond the inherent variability of RE (wind and solar). The exact consequences of any of these trends are complex and difficult to predict. Their ripple-effects may range from simple variations (both temporary swings and higher volatility) to substantial or secular changes in electricity demand and supply patterns.

Factors Influencing an Optimal Supply Mix

As Tongia (2022) examines in detail in his study on India's grid in 2030, the optimal supply mix depends heavily on assumptions, both for supply and demand. On the economic side, these depend on technology and fuel costs (and finance costs). But equally important are the technical assumptions on demand and variable supply profiles, especially at a high time resolution. Even an hourly analysis may not suffice for optimal supply planning to understand per minute ramping requirements, which can be a constraint for some fuel types—this is before one considers load-flow technical analysis which can focus on transient load-flows and dynamic stability (sub-second issues). This paper helps understand supply and demand profiles, and while it only uses a single year data, this exemplifies a possible shape curve and also highlights policy insights.

Non-financial factors impacting optimal supply mix:

1. *Variability of wind and solar* are well known, but the long-term output expected can change over the years, a factor that will worsen with climate change. Even hydro supply varies year-on-year;
2. *Variability in Demand (time-of-day)* is important for choosing supply to meet demand. There will inevitably be a daily peak—when and for how long it occurs impacts optimal supply options, more so with VRE like wind and solar;
3. *Seasonal demand variability* has similar but more challenging implications than just time-of-day, since storage and demand shifting is much harder across seasons. If one built a battery, one would hope to use it daily instead of just a few days or weeks in a year. Cooling is a key factor for both sets of peak demand (daily and seasonal), but monsoons have other implications as well. Demand can fall due to not just temperature shifts but also reduced irrigation needs. On the supply side wind output increases, and hydro reservoirs fill up and even become "must run" or nearly so, meaning they have to release water independent of power demand.

4. *Location* is important for choosing the optimal fuel mix—both for supply and demand. Not only is coal cheaper near the pithead, wind and hydro resources are heavily geographically constrained. In fact, all power plants choose locations not just based on demand but also on fuel supply and transmission. More transmission lines can partly address this issue, but at a cost;
5. *Correlation and network effects*—addition or reduction of output from one source impacts the burden on other sources, and some fuels may interplay through sequencing based on their time constants of ramping. We may need both fast ramping solutions to instantly meet swings in demand, but also more long-duration balancing solutions that may take many minutes or even an hour to change output.
6. *Expected duty cycle* emphasises the disconnect between capacity (kW) vs energy (kWh). Not only are PLFs sometimes constrained, some plants have high fixed costs but low variable costs (or even zero, like for most RE). Such plants should operate first in the merit order dispatch, which impacts fuel requirements down the chain; e.g., a gas plant built as a peaker may not always have sufficient fuel to run as a baseload plant.;
7. *Technical characteristics of fuel types* go beyond just fixed versus variable costs but include factors like ramping rate capabilities, minimum operational times (that impact start-stop operations), etc.

Studying granular time-of-day and seasonality data is essential for long-term energy planning and policy making across the country. Accurate, consistent, and granular data help recognise patterns that can reduce challenges arising from uncertainty and variability. Demand forecasting and extrapolating past trends in energy supply are also important. Put together, these can help optimise the necessary fuel mix, a calculation that may go beyond economics and factors in grid security, environmental impacts, etc.

Historically, there has also been uncertainty, but much of this was for demand; supply was assumed to be firm. Going forward, high RE in the supply mix changes the system design. Previously, demand varied, and we only had to build sufficient capacity to allow for a buffer, and one could turn supply sources on or off to match the (varying) demand. Now, with VRE, even the demand is variable, and, at the extreme, no amount of over-engineering can meet the demand (e.g., evening demand can't be met by even infinite solar capacity, at least not without storage).

Meeting the Many Needs of the Grid: Balancing, Ramping Requirements, and More

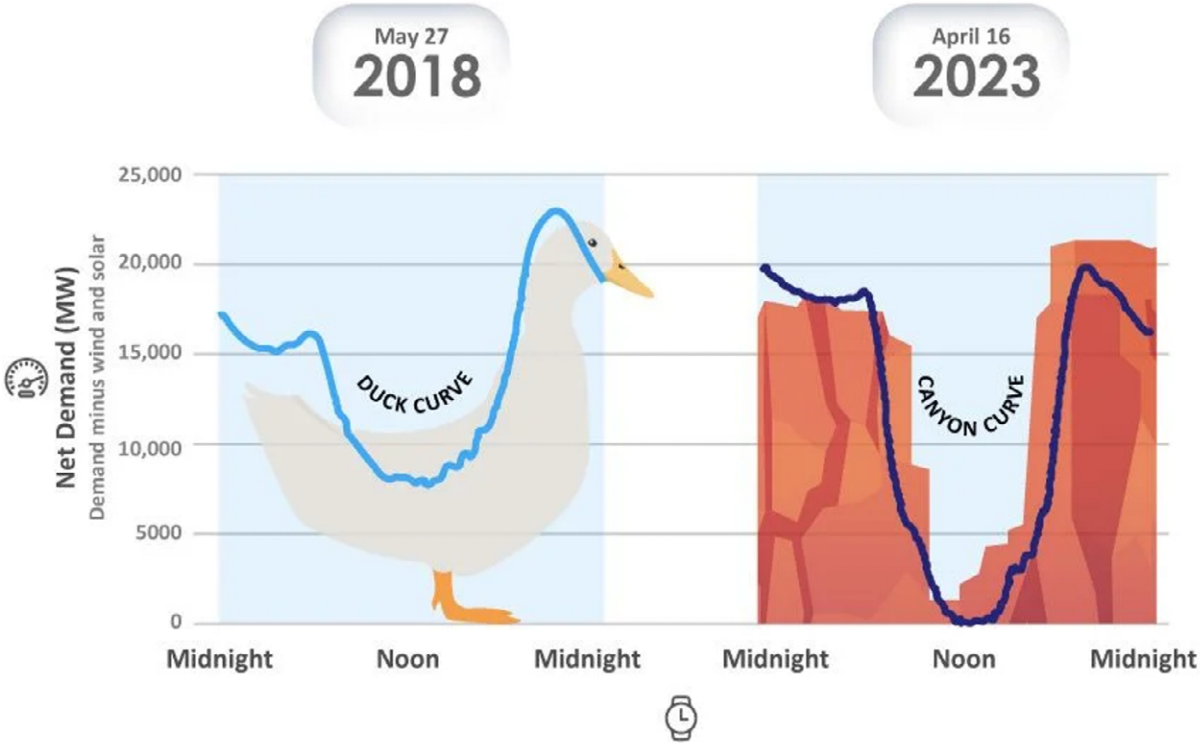
A well-operating grid needs real-time balancing of supply and demand, but this is more than having enough capacity, or even potentially available energy. As we've seen, capacity and energy don't match (Figure 2). Even energy isn't equal at all times of the day or year. Uncertainty further complicates analysis, often resulting in a statutory buffer in capacity and supply capability.

All the operations are meant to keep both the voltage profile of the grid and the frequency (cycles per second) within bounds. Constraints like the ability to increase (or decrease) output, also called ramping, are another key technical constraint in grid planning. *Different fuels have different ramping capabilities*. For example, hydro can be ramped up/down in tens of seconds, while thermal power might take an hour to measurably ramp up/ramp down. However, hydro energy generation often depends on seasonality. Natural gas is considered very flexible, but India has limited gas resources. Nuclear power is firm, but not very easy to ramp up or down.

Many of the above trends collide when we have a high RE system. California's grid gave insights into a future problem where high RE and sufficient capacity still meant challenges because of ramping requirements. This became the classic "duck curve" due to its shape (Figure 1).

A duck curve plots the hours of the day (March 31, i.e., a spring day) against ramp in electricity generation (in MWs), from 2012 projected out to 2020. Shaped like a duck, it demonstrates the ramp down of net-load (i.e., non-RE) generation as solar-energy generation fills in during the daylight hours, and the corresponding ramp-up of net-load during the evening. With passing years, the curve predicts a higher dependence on RE generation during daytime, hence making the evening ramp sharper with time. We are already seeing the start of the duck curve in India. However, with growing RE in California, the duck curve is turning into a "canyon curve", which has much steeper ups and downs, and also can go down to *zero* net demand when solar output is high in the middle of the day.

Figure 1: Impact of RE on Net Demand in California—Growing from Duck Curve to Canyon Curve



Source: Patel (2023).

About CSEP's Electricity and Carbon Tracker

> *Electricity is a real-time service, and one needs real-time data matching demand and supply to understand the balance; CSEP has built one of the first public tools for this in India.*

The CSEP Electricity and Carbon Tracker is a near-real-time online tracker that shows electricity generated by source (e.g., renewable, thermal, etc.) at a national level. It also shows total electricity-based carbon dioxide (CO_2) emissions every five minutes and CO_2 emissions per kWh in aggregate based on official emission factors per fuel type. Additionally, it shows various moving averages for each generation source, as well as a wide variety of summary statistics and analysis.

Researchers at CSEP (then Brookings India) built the Electricity and Carbon Tracker (https://carbontracker.in) in November 2018, because there was no source of high-resolution, historical electricity generation data at the national level and it was felt that a tool like this was a prerequisite to answering any sort of planning question—from sizing investment decisions overall to sizing batteries to keeping the grid stable.

Background and Implications of carbontracker.in/MERIT Portal Data

To build our carbon tracker, we created an automated tool (online at carbontracker.in)[4] that captures generation by source from the Government of India's portal, MERIT (Merit Order Dispatch of Electricity for Rejuvenation of Income and Transportation) every three minutes, and stores it in our database, and then calculates carbon emissions by fuel time in near real time. We apply simple algorithmic error correction and add visualisation and analytics for the public portal.

MERIT only captures all-India data, it does not break down RE across its components, viz., wind, solar, biomass, micro-hydro, and waste-to-electricity. The installed capacity (Table 1) and generation data from the National Power Portal (NPP) indicate the dominance of wind and solar within RE. If we consider national plans for 450 GW RE by 2030, as per CEA (2019), 420 GW are proposed to come from wind and solar. Renewable-energy capacity (excluding traditional hydro) on June 30, 2022 stood at just over 113 GW, while the capacity at the end of 2019 was 86 GW (Table 2).

Table 1: All-India Installed Capacity (MW and % share of total installed capacity) of Power Stations (as on December 31, 2019) (utilities)

Ownership	Mode-wise Breakdown (GW)					Grand Total (GW)
	Thermal (coal+ lignite)	Gas	Nuclear	Hydro	RE	
State	67,152	7,119	0	26,958	2,350	103,579 (28%)
Private	76,003	10,581	0	3,394	82,338	172,316 (46.7%)
Central	62,100	7,238	6,780	15,047	1,632	92,797 (25.2%)
Total	205,255 (55.7%)	24,937 (6.8%)	6,780 (1.8%)	45,399 (12.3%)	86,321 (23.4%)	368,692

Note: The values in the brackets show the share of each quantity in the Grand Total.

Source: Executive Summary on Power Sector (CEA, 2019, & 2020b).

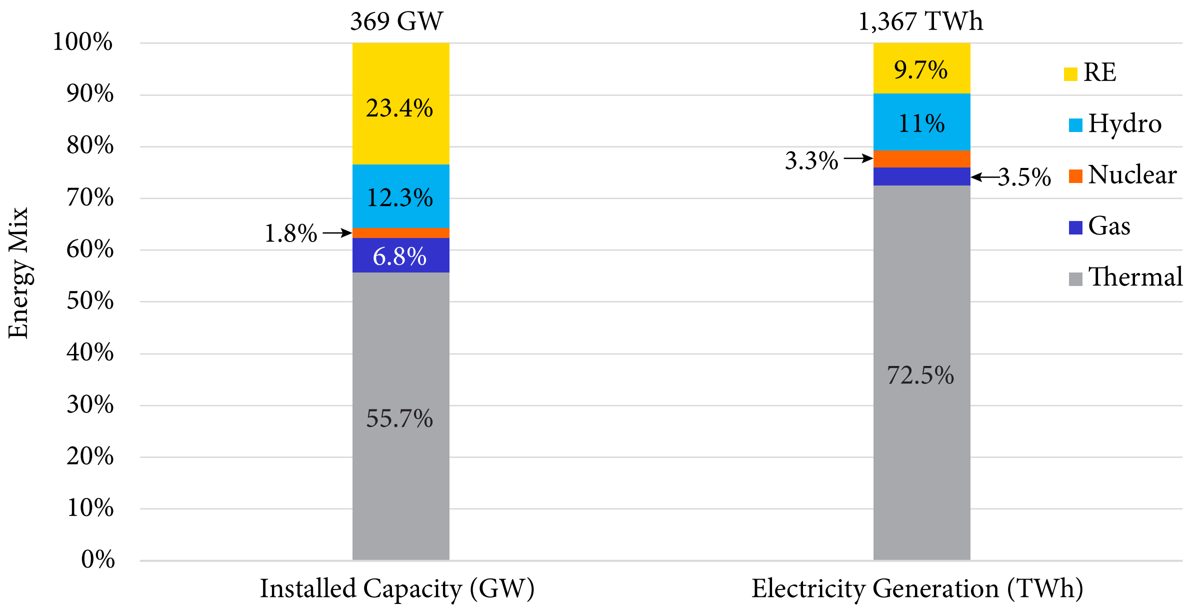
Table 2: Breakdown of RE Sources as of December 31, 2019 (MW and share % of total RE mentioned below)

Small Hydro Power	Wind Power	Bio-Power		Solar Power	Total RE Capacity
		Biomass power/cogen	Waste-to-energy		
4,677 (5%)	37,608 (44%)	9,861 (11%)	140 (<1%)	34,036 (40%)	86,322

Source: Executive Summary on Power Sector (CEA, 2020b).

[4] This tool is independent of the global group carbontracker.org.

Figure 2: Shares of Installed Capacity (MW) versus Utility Generation (GWh) in 2019 for different Energy Sources in India



Note: These are gross installed capacities at a utility level (excluding captive power), and some small fraction of generation is consumed in-plant as auxiliary consumption, and thus not available to the grid at the busbar, which is what carbontracker.in and the MERIT portal capture. Not all these capacities may be online at the same time due to a combination of faults, maintenance, fuel-supply limitations, etc.

Source: Authors' analysis calculated from CEA data in 'Executive Summary on Power Sector' (CE A, 2019). Imports are overwhelmingly hydro, and small overall (under 0.5%).

Capacity is not the same as generation (Figure 2), and RE has a much lower PLF than most other fuel options. Thus, a doubling of total capacity entirely by growing RE capacity wouldn't double the output. This means for the same level of demand growth, India needs to add more capacity in the coming years if it relies on RE. This also means disproportionally higher investment, since RE is purely a capital cost play (with no fuel).

Best Available Data, 'MERIT', Still has Limitations and Errors which We Try and Clean

MERIT portal data are the best-available data on high temporal resolution electricity output by type, but suffer from two major errors. First, there are occasional glitches, where data sometimes freezes, or has impossible spikes. For instance, sources of generation sometimes temporarily increase or decrease dramatically. Because of this, we apply simple algorithmic error corrections. This corrected data can be seen under *Corrected Generation Data* on our carbontracker. The uncorrected data are available, under *Raw Generation Data*. The online corrections are limited, focusing on obvious errors such as negative outputs or supply exceeding maximum capacity. Post this, there can be a few errors that remain, and which can only be corrected post-facto, comparing with other sources as well to see the big picture. Those are not part of the automated corrections in carbontracker.in.

The second error comes from limitations on coverage. Not all power plants are under the real-time data acquisition system used by NLDC for the MERIT website. Thus, the generation data from MERIT, and consequently the carbon tracker, do not match the daily generation reports by the grid operator Power System Operation Corporation Ltd (POSOCO) exactly—total generation per day in the tracker is slightly lower than the total generation per day in the POSOCO daily generation reports, indicating that not all plants are part of the real-time data capture. Renewable generation in the tracker is lower by about a few percent of the total demand met, but on a relative scale, RE's data are 30% short, varying by time period. However, since we do not have a breakdown of which RE plants are missing, we cannot make perfect corrections with time-of-day precision. We apply a simple proportional correction.[5]

Other generation fuels in the tracker are much closer to the daily reports data, which are expected to be accurate since they are post-facto and usually accurate due to stronger accounting norms for total energy (which impacts generator and transmission company payments) than for real-time generation. We do not focus on this error correction since we are interested more in the trends and variability, than in absolute levels of generation. For portions of this analysis, we have further manually corrected small spikes based on criteria of simultaneous (or missing) analogous falls. For example, a single source of supply cannot have a large spike if demand doesn't also go up or another source doesn't fall.

As mentioned above, the high-resolution data from MERIT also contains frozen data points over stretches of time where raw data on demand and supply mix don't appear to change. We have tackled these frozen data points via interpolation. These points (frozen + drastic erroneous values) are about 1.85% of total data, but the implications on calculations are much lower, since corrected or smoothened data are only expected to have an error from the true values by perhaps a few percent, making the effective total error likelihood under a percent. The gap between smoothened and likely actual data is only likely to have an error of up to a few percent in most cases, and typically lower. Thus, the total input data (and hence our analysis for 2019) are likely to be accurate to within 0.05–0.1%.

The correction of frozen points from extracted data is very important for our analysis for two key reasons.

1. If we are interested in ramp rates, since these compare readings with the immediate previous reading when the frozen cells stretch ends, there can be a sudden change in the readings as part of recovery. This otherwise leads to huge artificial ramp -ate spikes.
2. Frozen (or missing, where there is no reading) data lead to errors in total generation which can be calculated as the summation or integral of output (capacity operational) per time stamp. A linear interpolation as applied isn't a perfect solution, but reduces the error.

Total electricity generation across fuel types should, in principle, always be slightly higher than total demand, which is the demand as measured at state boundaries. This is because supply as captured is the busbar supply (i.e., post-auxiliary (in-plant) consumption), but before inter-state transmission losses (perhaps 1–2%), while demand is measured as the sum of demand at state boundaries. This national grid demand is higher than actual *consumer* demand, which subsequently includes transmission and distribution losses within states.

[5] We correct the RE data by scaling with a factor of ~1.3 for 2019, which brings RE's aggregate output (on KWh basis) in line with total RE generation as per CEA and NPP data.

Importance of Time-of-Day Data and Analysis

Electricity is a unique commodity where the present system, based on alternating current, requires supply to always meet demand in real-time; grid-scale storage is relatively limited. It is intuitive that demand varies over time, e.g., night time would be a low-demand period, but supply can also have variations. While some supply options—from fossil fuel power plants like coal (also called "thermal") are controllable or dispatchable, and thus called "firm" power, others have different constraints. In most countries, nuclear power usually only operates at rated output to the best extent possible, and doesn't go up or down much in response to load (a term called "load following"). Hydropower, though controllable at some level, does not have unlimited storage in the reservoir due to competing uses for water, as well as seasonality issues. The most extreme example of supply variability is with RE, especially without storage. Wind and solar depend on the weather or sunlight, and represent a "use it or lose it" source of power. However, in addition to expected variability (e.g., we know the solar output is zero at night, and peaks at mid-day), these also have stochastic output.

In a world with rising RE, it is important to understand the variability of both demand and supply to enable improved capacity planning to safely meet projected demand. This paper analyses India's 2019 electricity data; 2019 was the last year of data before COVID, which dramatically impacted demand. As Parray (2020) showed, in addition to muted demand due to COVID-19 lockdowns, on the supply side most of the reduction came from coal, which operates as India's primary swing producer. Some fuels can turn on or off more quickly, but the impact isn't as sustained as for coal, while in some cases as with hydro, any shifts in when power is generated doesn't impact the total annual output, which is rainfall (or snow-melt) limited. Supply swings during COVID-19 were distinct from consumer-side impacts, where the fall in demand was disproportionally from commercial and industrial users, who are important financially because they over-pay to cross-subsidise agricultural and residential consumers.

Literature Review and Paper Scope

Literature is scarce in this domain, primarily because of paucity of data. Most publications use limited resolution or synthetic data, e.g., NREL's use of wind models to calculate predicted wind generation in their flagship Greening the Grid report (NREL 2017). Power System Operation Corporation, the national grid independent system operator, has issued periodic reports on the operations of the grid, including recent guidelines on ramping rates (POSOCO, 2020). This has been preceded by a host of studies on ramping, grid balancing, and analytics, including a detailed analysis of electricity demand patterns in 2016 with decomposition of time-of-day and seasonality, down to the state level (POSOCO, 2016). Many of the studies were focused on 15-minute time blocks, or even hourly, but these were multi-year with time-series data. National Renewable Energy Laboratory, which has partnered with POSOCO and subsequently with states to study RE integration, also recently released a report on ramping and India's transition (Joshi et al., 2020). Titled "Ramping Up the Ramping Capability", the report highlights international experiences and also mentions that net demand ramping rates might become problematically high as RE grows.

In this paper, we examine issues of grid balancing and start from a high level, looking at the data as a whole, and then parsing the data more granularly to answer questions at the seasonal, monthly and sub-daily levels. Specifically, we provide descriptive statistics and insights on issues of correlations between fuel sources versus demand, ramping of output etc. One of the major needs is to understand how India will manage ambitious RE targets. One suggestion is to examine 'net demand'—a measure of demand post that met by RE as it is non-dispatchable (use it or lose it)—which we show on carbontracker.in.

We analyse data from five different fuels generating electricity in India, i.e., thermal, gas, hydro, RE, and nuclear, and the electricity demand met at a five-minute interval. Based on these, we can calculate correlations, ramping rates, and more across the fuel mix.

Starting with moving averages over the year for high-level trends, we then progress to correlations between the different fuels and their changes through the year. Even after breaking the correlations down to times of day and seasons, the daily swings and ramping rate trends/anomality are not visible.

Hence, we plot the daily maximum/minimum total electricity generation and net demand, daily swings, ramp rates through the year, and ramp rates split across time-of-day and seasons. These provide a complete picture, visualising the trends occurring through the year. Finally, we conclude the study with load duration curves of the fuel sources, plotting the duration in the year (in % of time) each fuel generates a range of electricity (in MW). Such a stacking gives a simple visualisation of the standard range of operation for each fuel, and how little time is spent in the extreme high/low MW range, proving that bursting ramps may be required but only for a shorter duration of time.

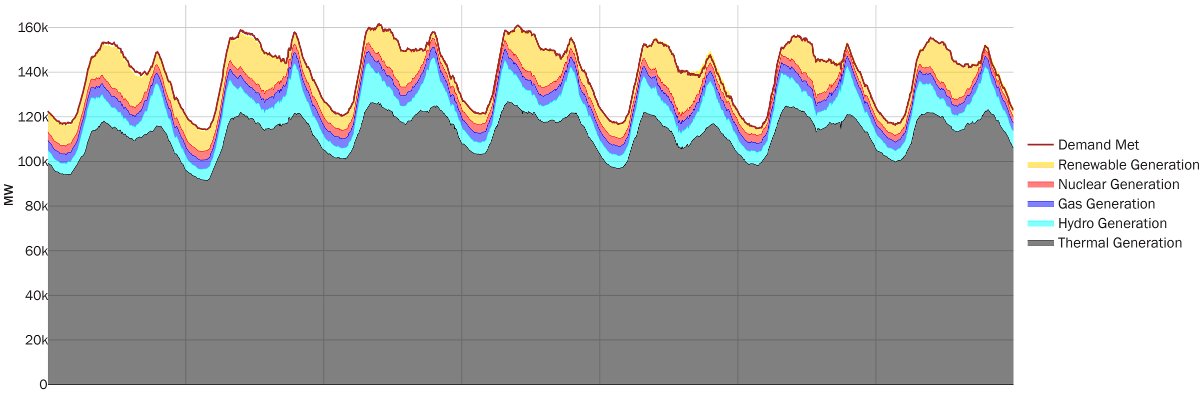
Findings and Analysis

We begin with simple visualisations and descriptions of the overall behaviour of the system in 2019.

Moving Averages Help Smoothen Variations

Figure 3 proffers the example of single week February 3–9, 2019. We can see daily variations quite clearly, and even the start of the duck curve (taking out RE which is in yellow). We can see that on a daily timescale, hydro is providing ups and down in output matching or following the demand, but we also note coal dominates the supply.

Figure 3: Carbon Tracker Readings of February 3–9, 2019

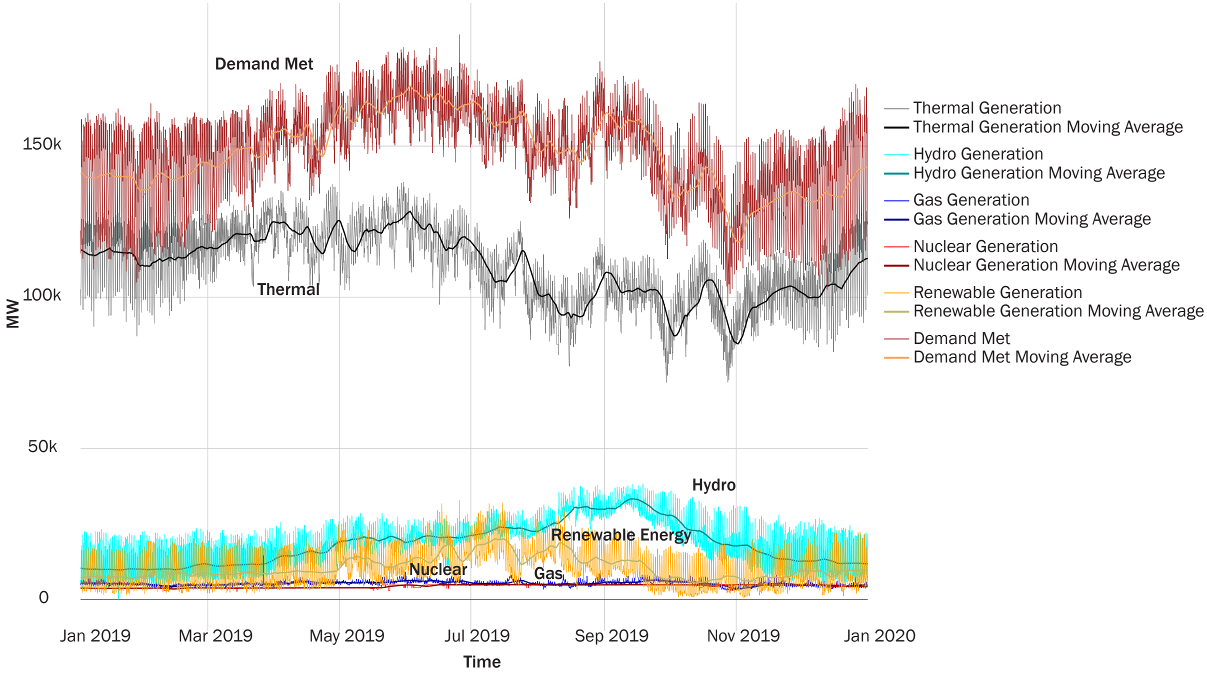


Source: carbontracker.in

If we tried to see the full year in a similar manner, it would look messy, and zooming in would simply show volatility. There are daily ups and downs, as well as single-day variations (as happens on weekends and holidays). Hence, a moving average (seven-day in this example) is a useful visualisation trend shown in Figure 4 taken directly from carbontracker.in (the tracker allows 24-hour and 30-day moving averages as well). While a moving average smoothens out daily and weekly variations, we can still see the impact of festivals like Deepawali on demand. Since these are five-minute interval data points, the ~vertical lines are respectively the daily variation for demand or a particular fuel source.

The Appendices show per fuel type outputs in more detail.

Figure 4: All-India Demand and Supply by Fuel at Five-minute Resolution with Seven-day Moving Averages (2019)



Source: carbontracker.in

Note: Demand is the grid-level demand at state boundaries, and close to the summation of the supply by respective fuels (coal, hydro, gas, nuclear, and RE). Each curve shows the weekly moving average to smooth out daily and weekend variation).

While moving averages are useful for trends, higher resolution measurements are important for studying ramping capabilities. The time constant for problems in the grid at a normal operations balancing level (ignoring frequency response, which can be measured in seconds or sooner, or grid faults) is typically in the 5–15 minute range. Indian pricing and grid management today is at 15-minute time blocks, and there are plans to tighten this to 5-minute blocks.

A few insights into high-level trends:

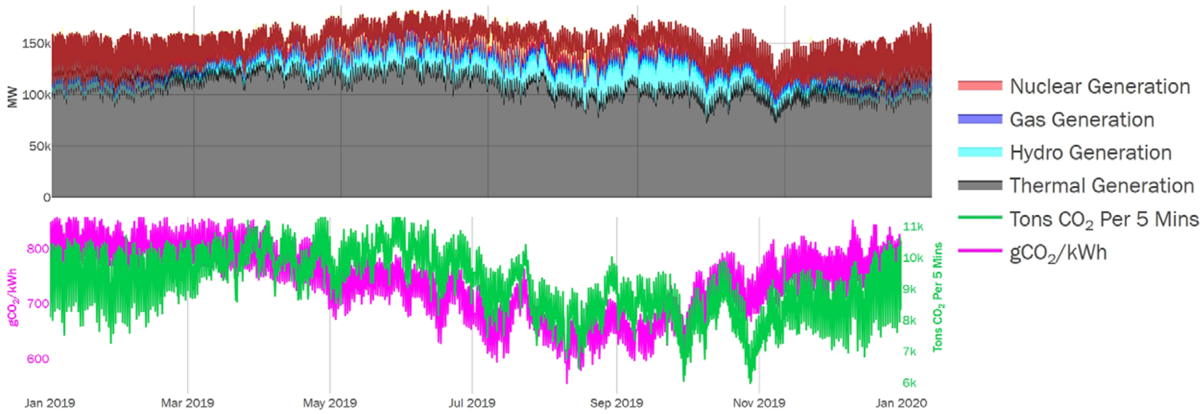
1. Total demand is highest in June and July, with a second peak around September, after the monsoon goes away.
2. Thermal generation appears to be mostly flat but rising between January and June, after which it begins to drop, even though demand remains relatively high.
3. This rising gap between demand and coal is made up by renewable generation (which begins to rise in May, mostly due to higher wind,[6] and by hydropower supply, which peaks shortly around September).
4. Hydro displays strong seasonality, post-monsoon.
5. Gas and nuclear generation are relatively flat throughout the year.

[6] The tracker doesn't separate wind versus solar within RE, but CEA's Daily Reports show the rise of wind in the middle of the year on an energy basis.

6. Demand rises mid-year, probably due to cooling requirements for the summer, such as air-conditioning, fan and cooler loads. Interestingly, in other periods of the year, the daily lows for demand drop much further, emphasising the time-of-day aspect of demand. This is hard to see at this scale but is clearly visible if we zoom in (a functionality available on carbontracker.in). During high-temperature time periods, nights do not show as low a demand. This should be further analysed in future studies, including those that examine temperature variations with demand, as well as those that attempt to segregate demand by consumer type for time-of-day implications.

Figure 5 shows CO_2 emissions compared to cumulative supply stacked by fuel. this stacked view is distinct from the individual curves by fuel type shown in Figure 4. Emissions are at their lowest in the second half of the year (July onwards), even though this is a time of relatively high demand. This is because coal generation touches a low during this period, while RE is high, as is hydro, post-monsoon. The pink line shows carbon intensity, which is more seasonal than total emissions per time block, which also reflects changes in volume. The carbon calculations are based on fuel-wise aggregate multipliers.

Figure 5: Output by Fuel and Resultant Carbon Emissions (2019)



Source: carbontracker.in

Correlations across Supply Types versus Demand

Given that demand is met continuously by a combination of supply types, the correlation between supply types and demand and with net demand (demand after removing RE), is important to understand average grid balancing and the contribution of different fuel types.

Year-long basis correlations

As expected, thermal generation is highly correlated with total generation. It is also even more correlated with net demand, showing the important balancing role it plays, driving total supply.

Table 3: Year-long Correlations between Total Generation, Net Demand and Supply Types in 2019

	Total Generation	Net Demand	Thermal Generation	Gas Generation	Hydro Generation	Nuclear Generation	Renewable Generation
Total Generation	1	0.817	0.682	0.636	0.472	0.022	0.526
Net Demand	0.817	1	0.811	0.706	0.461	-0.091	-0.057
Thermal Generation	0.682	0.811	1	0.456	-0.124	-0.496	-0.027
Gas Generation	0.636	0.706	0.456	1	0.472	0.125	0.065
Hydro Generation	0.472	0.461	-0.124	0.472	1	0.582	0.148
Nuclear Generation	0.022	-0.091	-0.496	0.125	0.582	1	0.190
Renewable Generation	0.526	-0.057	-0.027	0.065	0.148	0.190	1

Note: In this section and subsequently, the cells in red are only to highlight negative values.

Source: Authors' analysis.

Gas is slightly less correlated with demand than thermal, and, as expected, nuclear has no meaningful correlation—its operations are based on plant ability instead of demand ("must run" equivalent status).

Slightly counter-intuitively, hydro doesn't have a higher correlation with net demand compared to total generation (aka total demand). We revisit this issue shortly. Renewable energy is only very mildly correlated with net demand, with a very small negative sign.

This aggregate picture misses two very important variations over the year: time-of-day and seasonality. Demand varies over both, as does RE supply (for example, solar is inherently available only during the day).

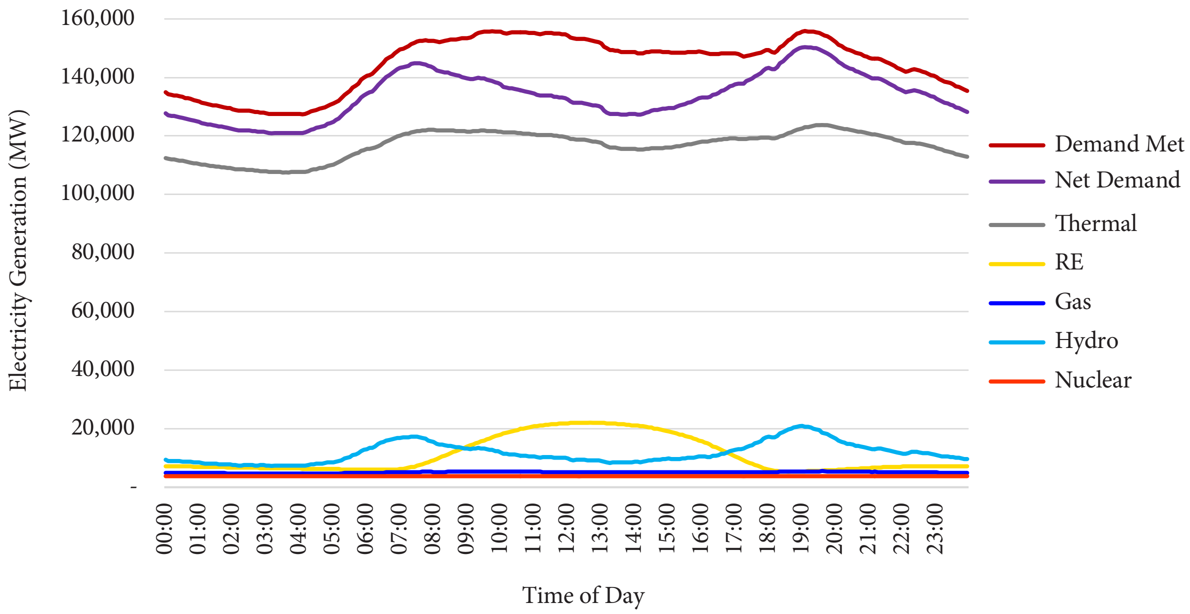
Importantly, we can visually see the change in relationship between RE versus demand compared to RE versus net demand (almost a mirror image). We can also affirm that nuclear generation is flat, independent of demand *or* other supply—its output is higher or lower due to supply constraints.

Understanding Variations by Time of Day and Seasonality

Given the variations by time of day, it is important to examine different time periods for how supply and demand intertwine. This will become more and more important as the share of solar rises in the mix.

Figure 6 shows the average daily profile for supply and demand. Note, on average the peak in 2019 was in the evening; if we consider net demand, the peak is more pronounced in the evening, and the evening ramp-up is steeper (the so-termed duck curve, with a mid-day belly when RE output is high, and a steep neck upwards in the evening). It's also important to note that while the gap between demand and net demand represents RE's contribution, Figure 6 shows the 24-hour average across the year. There are many days where the RE contribution, especially in the evening, is much lower. Capacity planning has to be based on instantaneous supply and demand, and not on averages. We focus on all time slots in other sections of the paper.

Figure 6: Average 24-hour Time-of-Day Profiles (2019)



Note: This shows the average 24-hour profile across the year, across all supply sources, as well as load served ('demand') and net demand.

Source: Authors' analysis.

For some of our analysis, we break up the day to span several daily time buckets largely representative of demand profiles:

1. Morning—increase in load, largely driven by residential demand.
   Timing: 6 a.m. to 10 a.m.[7]
2. Mid-day—driven by commercial and industrial demand; coincides with high solar.
   Timing: 10 a.m. up to 2 p.m.
3. Late Afternoon—decrease in solar.
   Timing: 2 p.m. up to 6 p.m.
4. Evening—high demand with some overlap of commercial and residential; late periods include heavy air-conditioner use; depending on season, limited RE contribution.
   Timing: 6 p.m. up to 10 p.m.
5. Night—driven by residential demand, and historically by agricultural supply, which was controlled ("rostered") to be supplied during off-peak periods.
   Timing: 10 p.m. up to 6 a.m.[8]

[7] Time blocks are five-minutes, so the last reading in this bucket is 9.55 a.m.

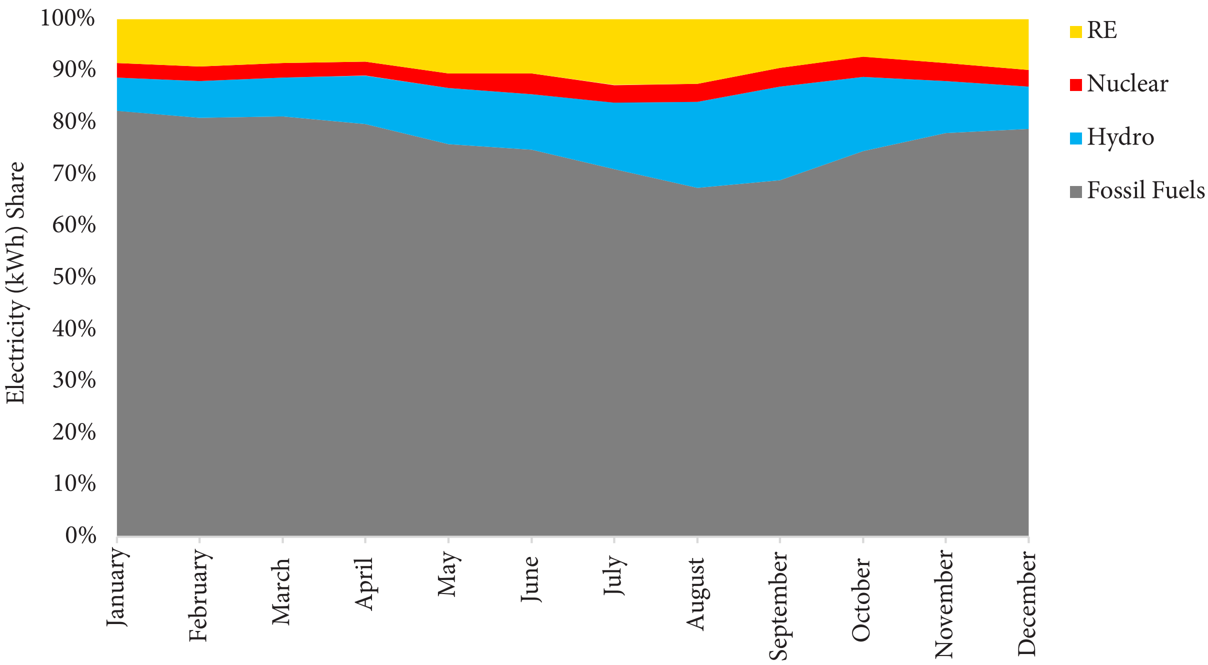
[8] A number of states are now shifting agricultural supply to periods around mid-day, to match increased solar supply. This is complementary to the push to solarise agricultural pump-sets, e.g., under the PM-KUSUM scheme.

We similarly break up the year into the following seasons to represent demand profiles accordingly. In practice the changes in temperature and precipitation aren't fixed, but these are sufficient to give us more insights than annual aggregates:

1. Winter (December to February; spans across calendar year, ideally)
2. Summer (March to May)
3. Monsoon (June to August)
4. Post Monsoon (September to November)

Figure 7 shows the monthly split of electricity by fuels. This is based on CEA data, which clubs all fossil fuels (especially coal and gas, with trivial diesel) together.

Figure 7: Monthly Split of Electricity by Fuels (2019)

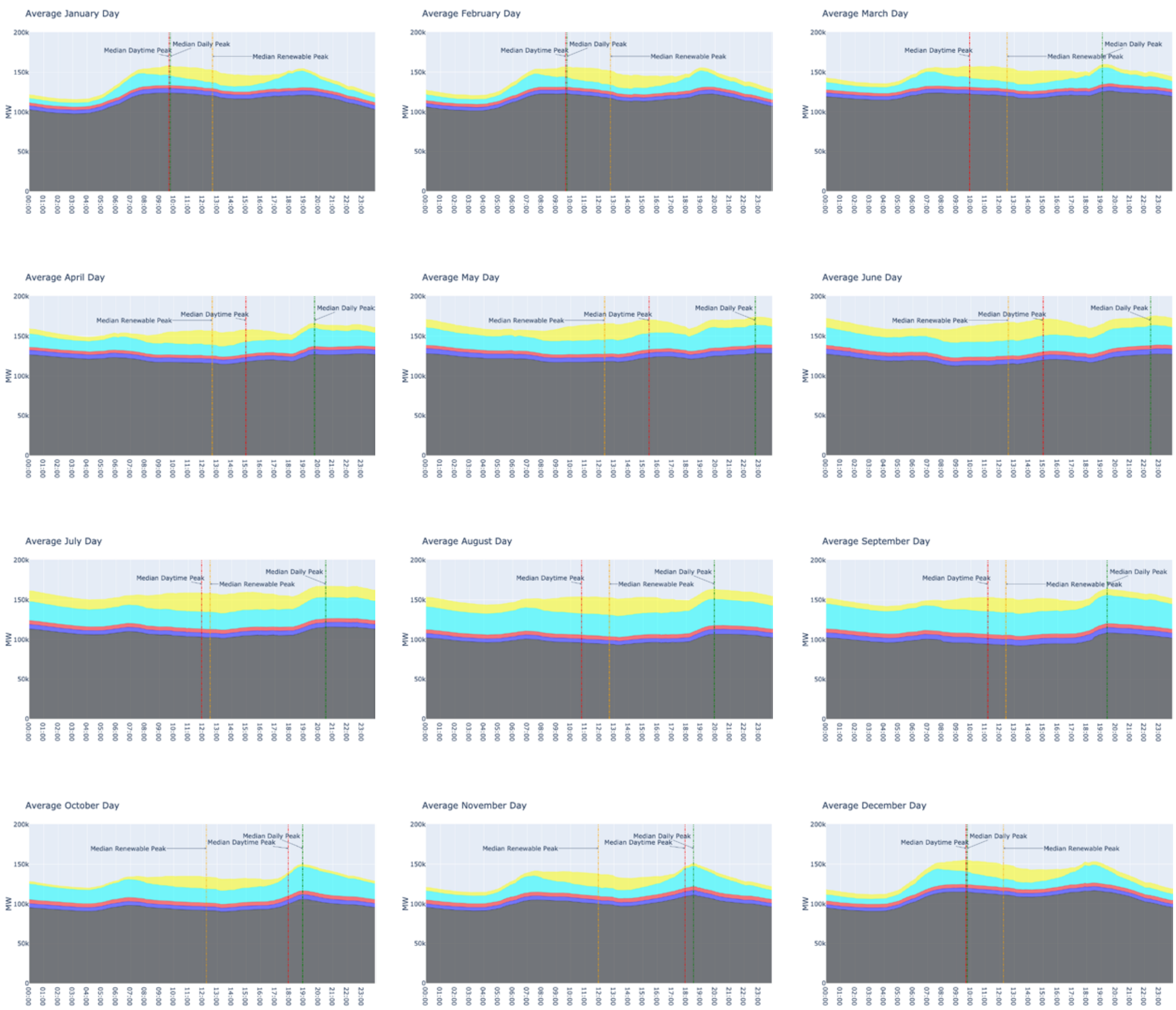


Source: Authors' analysis from CEA Monthly Executive Summary Reports (January 2019–January 2020).

We can see the strong seasonality of hydro, dipping into fossil output. Renewable energy also shows some seasonality with wind around and immediately post the monsoon, but this effect is not as visible as one would expect due to an artefact of methodology. As RE capacity is growing rapidly, the end of the year will show an inherently higher output even if the PLF doesn't change as much between December versus January. A separate analysis would need monthly capacity by fuel to examine PLFs. Only RE is growing rapidly out of all the fuels, more so on a percentage basis.

Because monthly aggregates lose time-of-day-level data, it is illustrative to see how the time-of-day curves change over the course of the year (Figure 8). The three coloured vertical peaks are the median day-time peak (maroon), median renewable peak (yellow), and median daily peak (green). We can see that the daily peak comes in the morning some parts of the year, but shifts around seasonally. We can also see that the daily net demand peak (peak demand removing RE supply, not shown separately) remains in the evening throughout. We can also see hydro shift from the sharp bimodal (morning evening) peak seen in Figure 8 to one where its output becomes much steadier throughout the day. This shift from a traditional load-following role to almost must-run, occurs during and after the end of the monsoon.

Figure 8: Average Daily Electricity Generation Trends Month by Month (2019)



Source: Authors' analysis.

While these two metrics are illuminating, it is insufficient to examine either time-of-day or monthly curves in isolation. Putting both together helps us better understand the shifts in the peak, ramping, contributions of different supply options, etc. We do so both visually, and, subsequently, statistically.

The post-monsoon season becomes interesting because wind seems to die down and hydro is unable to ramp as much having turned into nearly must-run mode. This indicates that balancing and ramping can become issues in this season. We revisit these issues subsequently.

Breaking the Year into Buckets: Seasonal and Time of Day

The annual correlations shown in Table 3 mask important differences across time of day and seasons. Table 4 shows the per-fuel correlations, with both demand and net demand split into time-of-day and seasonal buckets.

Table 4: Annual Supply Correlations Broken into Seasons and Time-of-Day (2019)

THERMAL											
Correlated to Total Supply	Winter	Summer	Monsoon	Post-Monsoon	Annual by ToD*	Correlated to Net Demand	Winter	Summer	Monsoon	Post-Monsoon	Annual by ToD*
Morning	0.823	0.582	0.721	0.635	0.636	Morning	0.888	0.919	0.850	0.733	0.836
Mid-day	0.849	0.675	0.851	0.648	0.651	Mid-day	0.891	0.860	0.915	0.666	0.808
Late Afternoon	0.832	0.719	0.867	0.605	0.633	Late Afternoon	0.793	0.893	0.935	0.772	0.810
Evening	0.847	0.694	0.853	0.715	0.583	Evening	0.860	0.875	0.870	0.775	0.723
Night	0.922	0.928	0.787	0.811	0.796	Night	0.973	0.923	0.926	0.814	0.857
All day by season	0.910	0.662	0.788	0.687	0.682	All day by season	0.924	0.896	0.904	0.796	0.811
GAS											
Correlated to Total Supply	Winter	Summer	Monsoon	Post-Monsoon	Annual by ToD*	Correlated to Net Demand	Winter	Summer	Monsoon	Post-Monsoon	Annual by ToD*
Morning	0.439	0.418	0.534	0.568	0.486	Morning	0.491	0.274	0.678	0.650	0.510
Mid-day	0.384	0.461	0.629	0.621	0.523	Mid-day	0.468	0.485	0.721	0.683	0.586
Late Afternoon	0.376	0.629	0.612	0.610	0.529	Late Afternoon	0.472	0.670	0.745	0.716	0.632
Evening	0.507	0.766	0.559	0.720	0.640	Evening	0.553	0.695	0.734	0.802	0.689
Night	0.293	0.775	0.648	0.238	0.767	Night	0.328	0.807	0.804	0.771	0.806
All day by season	0.584	0.696	0.625	0.657	0.636	All day by season	0.603	0.685	0.765	0.732	0.706

HYDRO											
Correlated to Total Supply	Winter	Summer	Monsoon	Post-Monsoon	Annual by ToD*	Correlated to Net Demand	Winter	Summer	Monsoon	Post-Monsoon	Annual by ToD*
Morning	0.103	0.338	-0.390	0.557	0.059	Morning	0.273	0.506	-0.050	-0.040	-0.027
Mid-day	0.237	0.602	-0.439	0.669	0.224	Mid-day	0.303	0.447	-0.244	0.022	0.057
Late Afternoon	0.058	0.685	-0.414	0.658	0.292	Late Afternoon	0.666	0.691	-0.224	-0.072	0.196
Evening	0.765	0.772	-0.090	0.741	0.484	Evening	0.780	0.674	0.116	0.723	0.419
Night	0.586	0.879	0.499	0.827	0.668	Night	0.532	0.849	-0.083	0.851	0.619
All day by season	0.576	0.708	-0.181	0.723	0.472	All day by season	0.781	0.760	0.057	0.778	0.461
RE											
Correlated to Total Supply	Winter	Summer	Monsoon	Post-Monsoon	Annual by ToD*	Correlated to Net Demand	Winter	Summer	Monsoon	Post-Monsoon	Annual by ToD*
Morning	0.548	0.408	0.268	0.487	0.491	Morning	-0.036	-0.511	-0.647	-0.099	-0.270
Mid-day	0.129	0.441	0.254	0.564	0.509	Mid-day	-0.315	0.021	-0.444	0.272	0.003
Late Afternoon	0.077	0.480	0.275	0.443	0.543	Late Afternoon	-0.722	-0.113	-0.381	-0.141	-0.120
Evening	-0.389	0.494	-0.007	0.538	0.555	Evening	-0.594	0.044	-0.576	0.147	-0.002
Night	-0.102	0.394	0.007	0.805	0.615	Night	-0.397	0.391	-0.400	0.302	0.352
All day by season	0.518	0.439	0.200	0.427	0.526	All day by season	0.031	-0.279	-0.563	-0.130	-0.057

Note: ToD= time of day. For our purposes, we assume supply matches demand, with minimal effects of load-shedding.*

Source: Authors' analysis.

The above do not show data for nuclear, as it is a demand-inelastic supply.

A few observations:

1. Thermal is most correlated with demand during the night, which makes sense for two reasons. First, RE is low (solar is zero). Second, hydro is chosen as a peaker so isn't used as much during the night, on average. As expected, thermal is more correlated with net demand than demand, not just on average but across almost every time block.
2. Gas has a medium but positive correlation with demand, but similar to coal, a higher correlation with net demand. It also has higher correlation during time periods of the day when RE is low.
3. Hydropower also has modest positive correlation, but much greater variation across time blocks. Most of the monsoon, it is negatively correlated with demand (and even net demand). On a daily basis, in certain seasons it is the evening or night where it is highest correlated. The two seasons with highest correlation with demand are summer—which has high demand—and post-monsoon, when hydro turns close to must-run.
4. Renewable energy also has high variation across blocks, and has the lowest correlation during the monsoon. The fact that it is mostly negatively correlated with net demand isn't unusual since net demand is defined as the demand post subtracting RE. What is worrying for the future is that the evening and night are periods of low correlation with demand, which is when net demand can be high.

It's worth emphasising that our boundaries for time blocks or seasons are intuitive, and not based on precise data. These would shift in an intertwined manner, e.g., in the summer, daylight extends and so RE's output would differ compared to the winter for the same "late afternoon" which ends at 6 p.m. This is one reason a visual examination of trends is also helpful.

Correlation statistics are also limited by the fact that they inherently smoothen out positive and negative values, something also better seen in visualisations.

Grid Balancing also Needs Ramping Up and Down

Thus far, we have focused on the aggregate picture of supply balancing. However, as the duck curve emphasises, there is a need to match all time periods of demand with appropriate supply (at least cost). Part of this involves ramping up (or down) supply options, and the role of "peakers".

Peaking power plants can have two overlapping roles. First, these may be chosen to operate only part of the time (the peak periods, by definitions). In some cases, that means choosing a supply option with (relatively) lower capital costs even if that means higher operating costs for the periods it does run, e.g., gas is traditionally viewed as a peaker instead of coal. The second role is for quickly changing the output in response to changes in grid conditions including demand, i.e., fast ramping. Here, again, gas wins over coal. The fastest ramps from traditional sources are from hydropower, though new batteries can have even faster ramping (but of limited duration, typically).

Year-long changes (Δs) in generation

Ramping performance can be measured at two levels. First, there is the measure of how much a power plant can change its output, either in absolute terms (MW/min) or relative terms. Absolute measures are important in aggregate since our net demand curves will tell us how much power swings require ramping support.

A complementary metric is to examine ramping of options in conjunction with how demand swings. These would be measured by the changes or deltas (Δ) in demand and corresponding fuel changes; e.g., if demand grew by 10,000 MW in five minutes (perhaps close to a 2%/minute swing, which is extreme), how would that be met?

Correlations of these deltas provide an aggregate picture of incremental balancing—change in demand (or net demand) versus change in fuel supplies (Table 5).

Table 5: Year-long Balancing (Δ) Correlations between Total Generation, Net Demand and Supply Types (2019)

(Delta)*	Total Generation	Net Demand	Thermal Generation	Gas Generation	Hydro Generation	Nuclear Generation	Renewable Generation
Total Generation	1	0.664	0.715	0.230	0.622	0.033	0.310
Net Demand	0.664	1	0.726	0.250	0.704	-0.019	-0.394
Thermal Generation	0.715	0.726	1	0.168	0.279	-0.037	-0.147
Gas Generation	0.230	0.250	0.168	1	0.102	0.001	-0.056
Hydro Generation	0.622	0.704	0.279	0.102	1	-0.009	-0.255
Nuclear Generation	0.033	-0.019	-0.037	0.001	-0.009	1	0.033
Renewable Generation	0.310	-0.394	-0.147	-0.056	-0.255	0.033	1

Note: Delta = change in (per time period).*

Source: Authors' analysis.

Compared to simple correlations between demand (Table 3), the three biggest changes looking at deltas are as follows.

1. ΔHydropower is now much more correlated with Δdemand and Δnet demand.
2. We can see a stark change in the performance of ΔRE, where the correlations falling measurably versus both Δdemand and Δnet demand, to the point of being negative with Δnet demand (which makes sense since net demand is demand post removing RE). ΔRE is now negatively correlated with all the other fuels, and not just thermal (Table 3) on annual correlations);
3. ΔGas is, surprisingly, much less correlated than overall gas (Table 3).

This last point indicates that gas operates as a balancing peaker, e.g., meeting evening peak demand, more than it operates to provide ramping support. Data indicate that as RE grows, assuming the shape profiles are similar, it would place a higher burden on other fuels to compensate ramping. This is based on the higher correlations of deltas each of gas, coal, and hydro for Δnet demand compared to Δdemand.

Time-block (time-of-day and seasonal) Correlations of ΔDemand versus ΔFuel

The previous section focused on annual correlations, but such analysis loses the richness of disaggregating across times of day and seasonality, both important since we know supply (and demand) aren't just varying randomly over time.

We perform similar correlations for different times of day and seasons, and have the following observations:

1. For Δthermal power, the maximum correlation with Δdemand is at night, which is ostensibly a period when other fuels are at their minimum. During the monsoon, the correlation of Δthermal with Δdemand is lower than other seasons.
2. Δgas has a lower correlation with Δdemand than gas does with demand (on average). This indicates gas is playing more of an energy-balancing role as a peaker than as a fast-ramping source.
3. In contrast, Δhydro has a measurably higher correlation with Δdemand than hydro's correlation with demand, which indicates its stronger role for short-run (five minute) ramping. ΔHydro has the highest correlation during the post-monsoon period, and a lower but still fairly positive correlation during the monsoon. This is visible from the 12-month time-of-day curves as well (Figure 8) where we see less variability during some months (approaching must-run equivalence). In addition to seasonality, the time-of-day difference is also strong, with maximum correlation of Δhydro during the morning, evening, and night periods (periods of low RE).
4. ΔRenewables (aka ΔRE) has a more scattered correlation with Δdemand. It is negatively correlated most evenings, but most strongly correlated in the mid-day and late afternoon. This is not surprising given the expected shape of solar output.

The Appendices show more disaggregated Δ correlations across times of day and seasons (Table A1 to Table A2, per fuel type, respectively.

These correlations are for short-run ramping, and discussions with experts indicate further research is required to study dispatch norms at state level and auto-correlations over continued periods. We have anecdotal data to show that for a long-sustained ramp-up in demand (well beyond five minutes), there can be multiple fuels interplaying, sometimes with negative correlations. For instance, in the very short run, hydro will respond fast, while coal will slowly ramp up. Over time, coal will then displace the hydro, even if overall demand may still be rising (albeit at a lower rate). *This complicates the simple analysis available from short-run ramping, which turns out to be a subset of the analysis needed for improved grid planning and policy (e.g., to incentive the "right kind" of future supply growth).*

Another limitation of viewing comparative shifts in absolute terms is that the scale of deployment may also matter. Given the coal fleet and output levels dwarf other fuels, on an absolute generation delta basis it is obvious coal (thermal) will have the highest correlations for five-minute deltas in demand. One exercise is to normalise the shifts based on volume per fuel being used, i.e., to use relative shifts. Table A2 in the Appendices shows the percentage delta ramps (five-minute) by fuel across the various time buckets.

Comparing the relative delta correlations versus the absolute delta correlations (Table A1 in the Appendices), we see that there is not much change for most fuel types, except the correlation (full year) declines in half for RE when we consider percentage delta correlations. For other fuels, there isn't much difference except a few time blocks move around a bit. This implies that the scale of deployment (being coal heavy) doesn't impact how much or little various fuels respond to changes in demand on a relative basis. Further research would need to understand nuances of marginal costs, dispatch optimisation, fuel limitations, and even issues like unit commitment—is a power plant on or off (only plants that are on can ramp up or down output).

Examining the same question of incremental balancing (five-minute changes) visually can show new insights. Figure 9 below shows the entire year's change in respective supply outputs to meet change in demand. These are not chronological but instead ordered by change in demand per five-minute block (the maroon line).

However, despite being so data intensive, even such an annual stacking shows the importance of visual interpretation—numerical correlations suffer from a smoothening effect of correlations; e.g., while Table 5 shows modest correlations of ΔRE with Δdemand, the actual relationship is a strong mix of much higher positive *and* negative correlations. The middle of the graph is quite noisy—increasing changes in demand find a mix of higher and lower RE. *But this average is misleading if we consider the tails of the graph, which are the extremes that are critical for grid planning.* Importantly, incremental (positive or negative) hydro and coal provide most of the swing for periods of high change in demand (positive or negative).

Zooming into the middle of the graph (Figure 10), not only do we see how RE's contribution to swings in demand are somewhat random (sometimes negatively and sometimes positively correlated), we can clearly see the need for hydro to align with changes in demand when RE's swing is against the change in demand.

This motivates examining seasonality and times-of-day blocks, which leads to a much sharper picture. Not only do we see more specific trends, these will have implications for the grid going forward as different supply types will grow at different rates in the future. Improved analytics, including proper segregation across times and seasons, could reveal the grid's dependency of each energy source for meeting ramp requirements depending on the season and time of day. This could also help structure time-of-day pricing better, and deploy energy sources to meet demand more efficiently, utilising sources such as RE and hydro to a greater extent.

Figure 9: All-year Graph of Δ demand versus Δ Supply Mix (2019

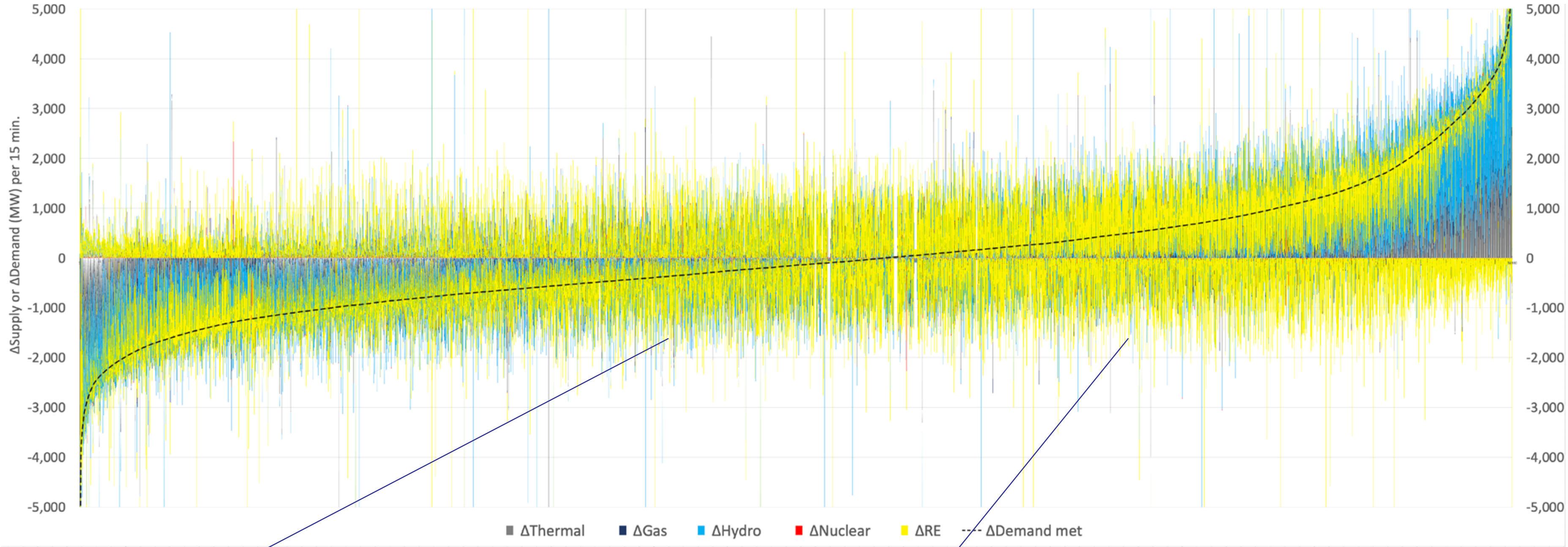
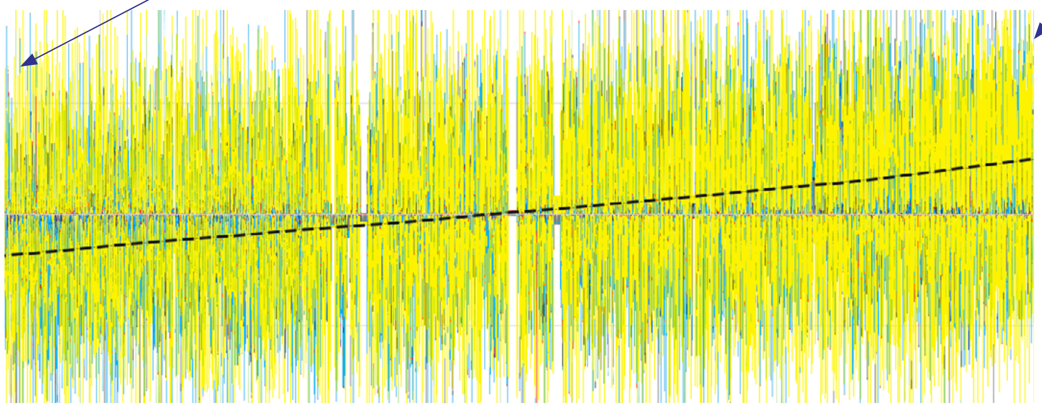


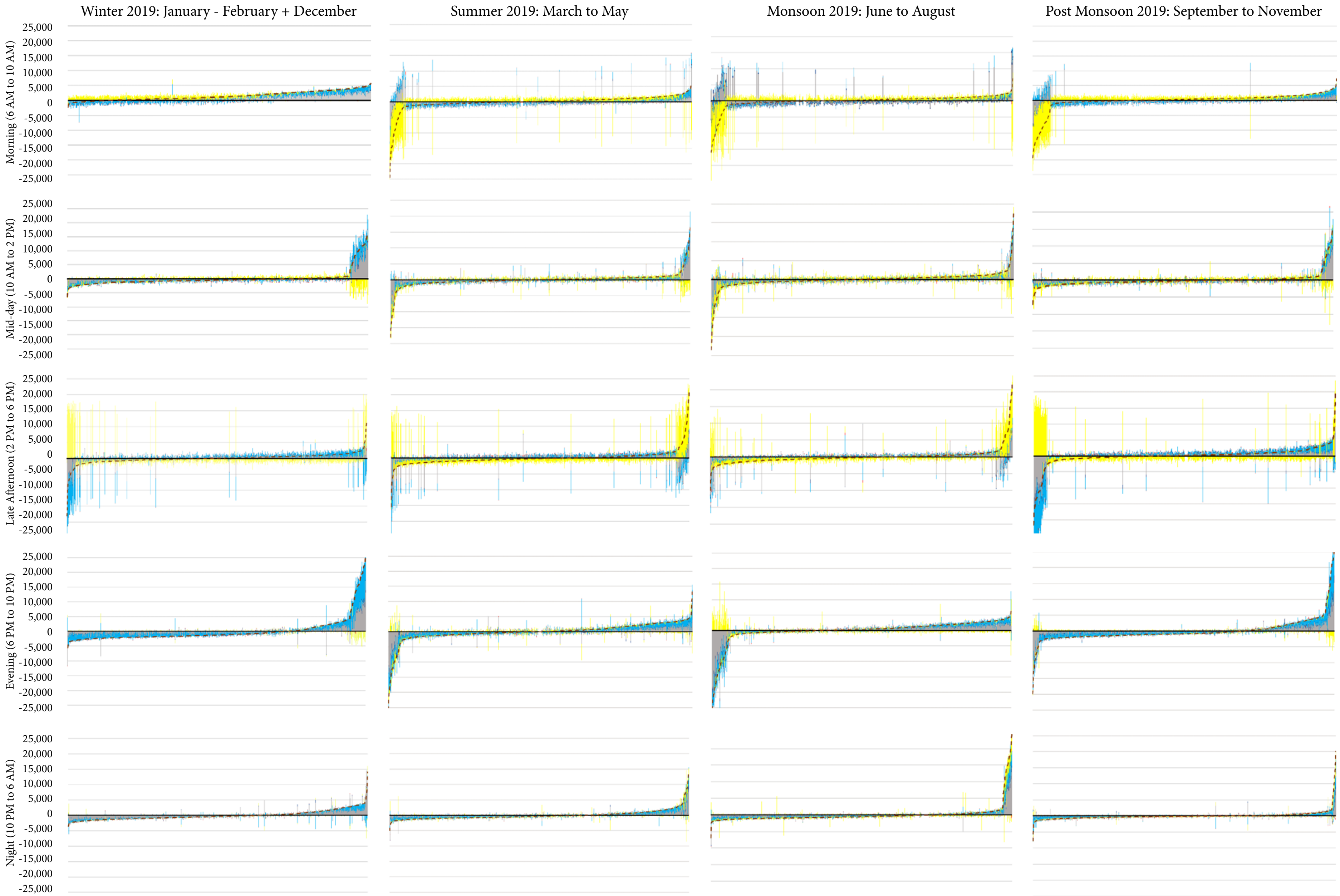
Figure 10: Zoomed in Section of Figure 9



Note: These graphs are not chronological, instead are stacked by increasing Δdemand between time periods.

Source: Authors' analysis.

Figure 11: Times of Day and Seasonal Segmentation of ΔDemand versus ΔSupply Mix (2019)



Source: Authors' analysis.

By breaking down the data across seasons and times of day shows the overwhelmingly (Figure 11) the overwhelmingly important role coal and hydro play in meeting demand shifts at the extremes, e.g., winter evenings. There are some cases where RE contributes well, e.g., summer evenings (perhaps due to favourable wind and extended daylight past 6 p.m.), but there are also periods where RE is negatively correlated with demand, sometimes rising in the late afternoon when demand falls the most. Falling demand is easier to manage than rising demand, and even this is met mostly with coal and hydro. Gas does swing, but it is hard to see at this scale.

The extreme periods and the evenings are the key areas of concern as those are periods for which we may need investments in new and appropriate capacity. We revisit this issue in the last section, Policy Implications and Discussion.

Importance of Daily Swings in Generation: Daily Minimum/Maximum

Daily swings in demand and matching supply may appear to be a subset of the time-of-day issue, but are an important metric and even design goal. For starters, it is intuitive that a high daily swing means lower average utilisation of peak capacity.

This isn't just an economic issue, of capacity utilisation, but one of technical constraints. Very few fuel choices are capable of load-following—going up and down based on demand. Fossil fuels can do so (albeit at varying rates). Hydropower can do so, but with an energy limitation in aggregate (based on annual rainfall). Nuclear is inherently inflexible, at least the Indian design plants.[9] Renewable energy (wind and solar) is not controllable, and can only be curtailed (thrown away) when it is surplus, and never increased based on demand per se, it is use-it-or-lose-it.

The issue of daily ranges is even more important for two reasons. First, much of the growth expected in the coming years is from solar power, even more so than wind, which has a pronounced daily shape. This means that the ability of wind (or hydro) to match non-solar periods with clean power will decline as solar grows disproportionally. Second, daily maximum and minimum outputs of coal power are a major technical constraint on how coal can operate.

One may want lower coal output mid-day as RE grows, but there is a technical limit to how low a coal power plant can operate at under part load (called flexible or flex-load operations). Coal plants are not designed for daily start-stop operations, so once a coal plant turns on, it should not be turned off at least for a day, ideally much longer. Thus, the maximum coal operates at in a given day tells us how low it can go the same day. Once this "flex limit" as it is termed is reached, then the RE would need to be thrown away ("curtailed"), even though it has zero marginal cost! Present norms by CEA ask for coal power plants to flex down to 55% operations, but a number of older plants reportedly cannot go down so low, not without retrofits and/or the need for co-firing the plant with expensive oil support. Even if coal plants can operate at part load, there is an efficiency penalty, one for which present compensation norms appear inadequate.

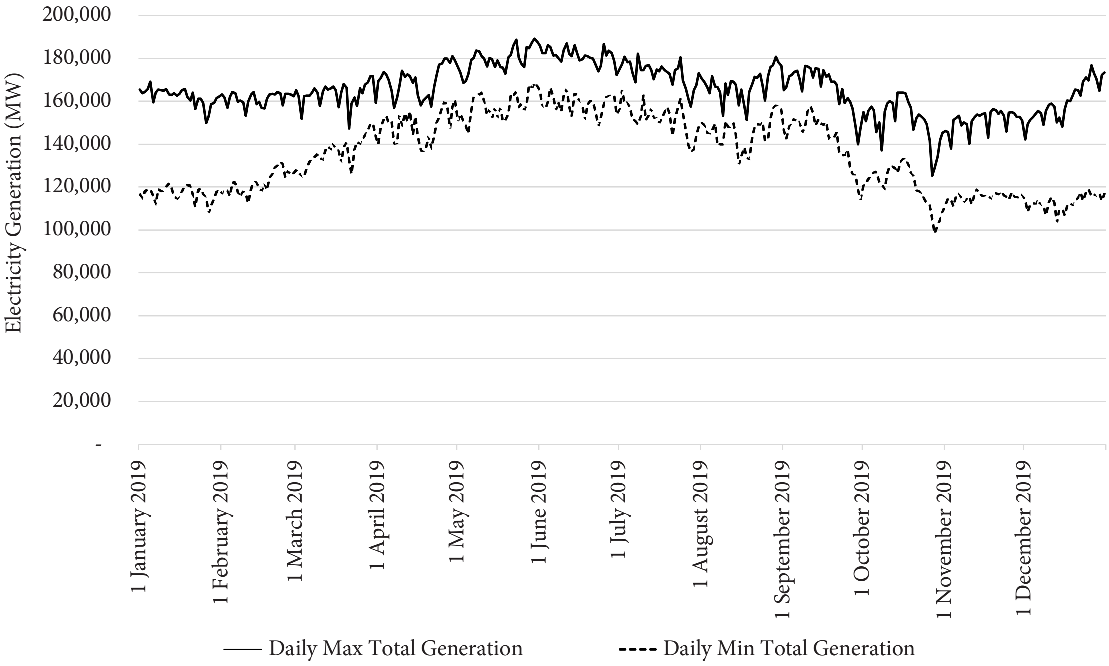
The starting point for examining daily maximum/minimum is for demand met, which is the same as supply (Figure 12). Both daily maximum and minimum generation peaked sometime around June for 2019. There is a secondary peak around September, which we will revisit shortly, and a winter rise as well. However, some of the growth towards the end of the year is simply organic growth over time, comparing the start of the year to the end of the year.

The gap between maximum and minimum supply (which we can use as a proxy for the daily range of total electricity demand) is smallest between April and September. This tells us that demand is

[9] France has newer generation nuclear plants designed for load following, that few countries have. Part of the reason is economics—the low variable costs of nuclear power mean it runs virtually all the time if possible—what used to be called baseload operations.

comparatively flat throughout the day during these months. Examining time-of-day demand, for overnight demand (and a rising daily minimum), indicates this is heavily driven by changes in air-conditioning demand.

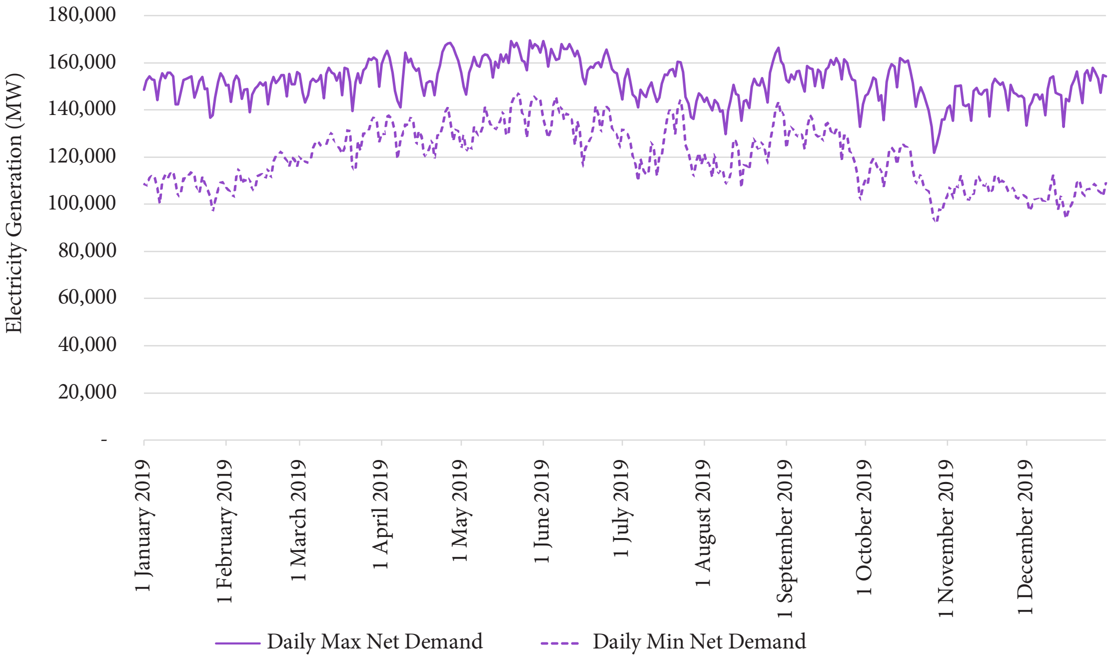
Figure 12: Daily Maximum and Minimum Total Generation (2019)



Source: Authors' analysis.

We see a similar but slightly less sharp trend with maximum and minimum net demand (total generation—renewable generation) in Figure 13. As expected, net demand is always lower than demand, but it is not equally lower throughout the year. In addition, the daily minimum doesn't track the daily maximum as closely for much of the year, indicating a variation in RE supply.

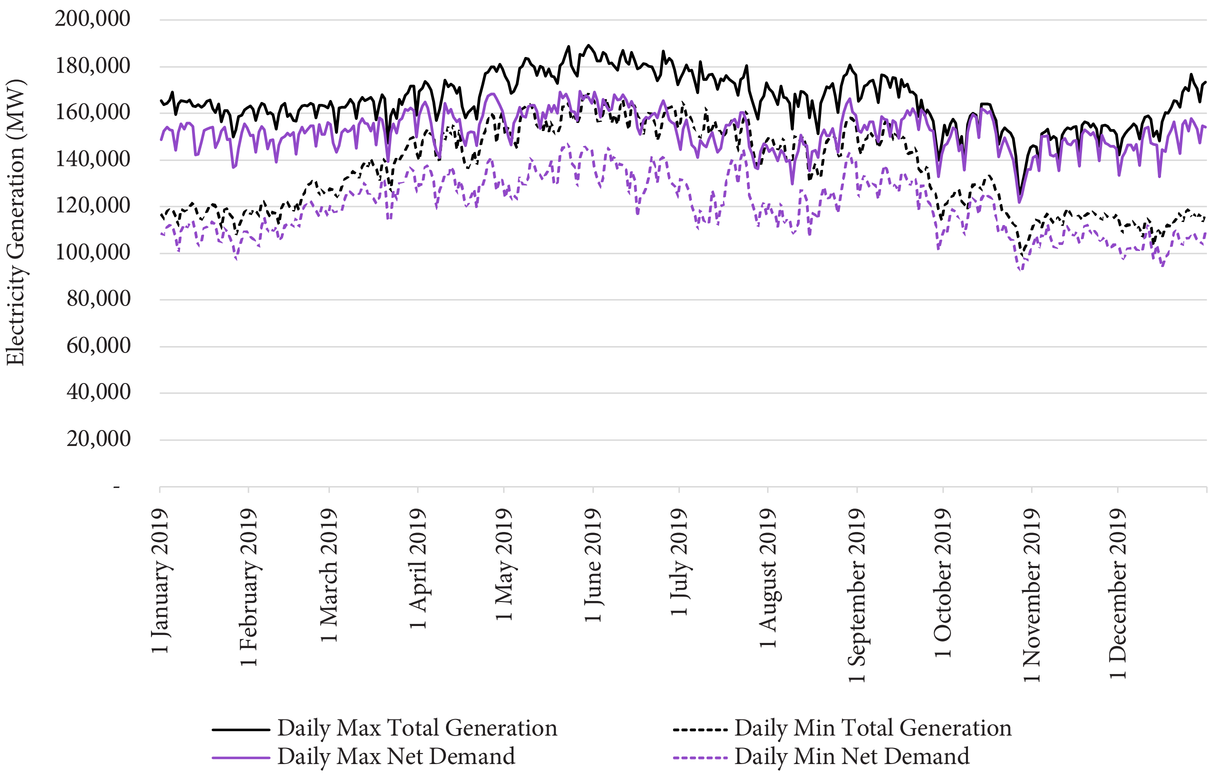
Figure 13: Daily Maximum and Minimum Net Demand (2019)



Source: Authors' analysis.

We can examine maximum and minimum total generation and net demand together (Figure 14). By seeing these together, we can get a visual sense of RE's contribution, and how much is happening at the daily peak versus at the daily minimum. We see that the gap between minimum/maximum generation and net demand is greatest from May to September, implying that that is when renewable generation contributes maximum demand. Rising RE could make volatility of net demand spreads, between high and low, worse over time. We can also see the period of very low RE, which is post monsoon, where the daily maximum total demand and net demand appear much closer.

Figure 14: Combined Daily Maximum and Minimum Demand as well as Net Demand (2019)



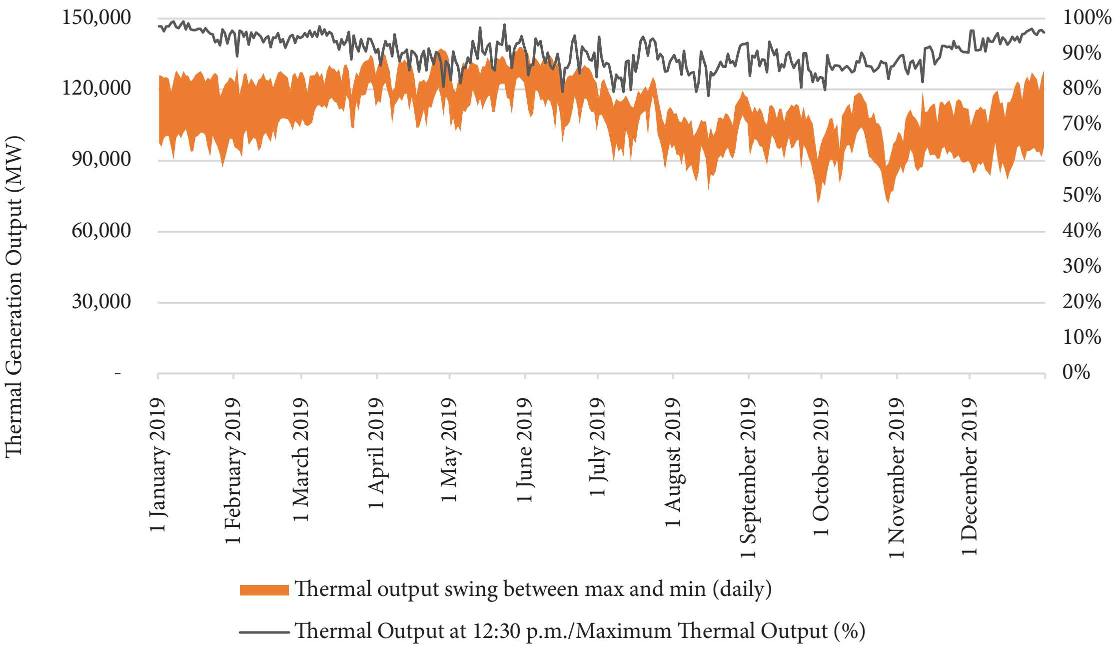
Source: Authors' analysis.

Daily swings in the context of growing RE: limits of coal swings

Using the data on daily maximum and minimums can help us plan for high RE future, given limits on how low coal's output can flex down to. To calculate this, we must first calculate the daily swing in coal output. Because our worry is about rising solar, we can compare output at 12.30 p.m., roughly the time of maximum solar (and often maximum RE).

Figure 15 shows the swing between the maximum thermal (coal) generation output (left axis in orange) and the thermal generation output mid-day (12.30 p.m.) as a fraction of the same day's maximum thermal output for 2019. We can clearly see seasonality—in the summer the coal output is highest and the swing between daily maximum-to-minimum is relatively low. This correlates with the daily low of demand rising in the summer, possibly due to overnight uses of air conditioning. The black line (right-hand side) shows that in the middle of the year, at 12.30 p.m., coal output is a slightly lower output than the daily coal max, indicating coal use maximises at another time. This could be due to a combination of an evening or other period peak demand, and also if alternatives are available for supply 12.30 p.m.

Figure 15: Daily Basis Thermal Generation Profile Over the Year (2019)



Source: Authors' analysis.

How will rising RE (especially solar) result in limits on lowered coal output? While this depends on the growth rates of both demand and solar, we can bound the issue.

As a thought exercise, let's examine how much growth of RE we can have before we have too much RE, measured by limits on flexible coal operations. Let's consider a maximum lower flexible operations limit of 60% for coal across the fleet—some plants can do better but some are worse. We already go down to 80% during the monsoon at 12.30 p.m. as Figure 15 shows.[10] Assuming minimal change in net coal fleet size, going down to 60% means approximately 22 GW of further mid-day output reduction capability from coal plants before we have "too much" RE which would need to be curtailed.

Of course, India is unlikely to add 22 GW of solar overnight, so if this takes one-and-a-half to two years, by then the peak demand would also rise, giving a bit more breathing room. This is also before large-scale storage, and assumes the demand shape doesn't change. By 2022, we can already see some increase in mid-day demand, which nicely coincides with solar output, buying us more time. But given demand and RE aren't growing at the same rate, India will soon thereafter face surplus RE which would start to be occasionally curtailed for grid absorption capability reasons.[11]

Daily maxima and minima of fuel types

Five-minute ramps are important for grid balancing, but given that demand swings are typically not very fast (even net demand), we should also consider a more gradual shift in outputs by supply type.

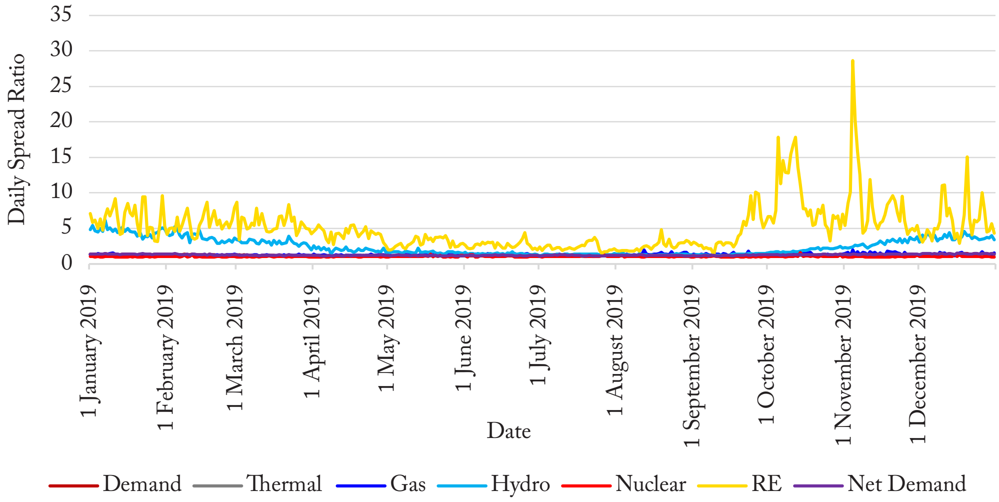
A pronounced version of this is to examine the daily maximum and minimum ratio or spread for each supply type and demand (Figure 16). This is important for coal power plants which are not capable of switching on or off easily and the daily maximum relates to the technical minimum in a near time period (such as daily). We note that RE has a dramatically higher daily spread (maximum

[10] This assumes no daily start-stop operations, a key operational choice. Start-stops are very expensive and cause wear and tear. Our estimates are in the order of 1 Rs/kWh for the coal plant *for the entire day's output*.

[11] Most curtailment of RE today is due to local grid congestion, transmission issues, or contractual reasons, as opposed to inability to utilise the RE at a national level.

to minimum ratio), especially post-monsoon. This is because night-time wind output falls sharply. Observing the details of the times-of-day of RE low and high are useful since we do not have a wind versus solar breakdown, and this graph validates the hypothesis of low wind after the monsoon. Hydro also has very a high daily spread, except during and near (post) the monsoon. Such volatility issues are critical for grid planning, which has to cover the year's "worst case" periods, and cannot be based on the average.

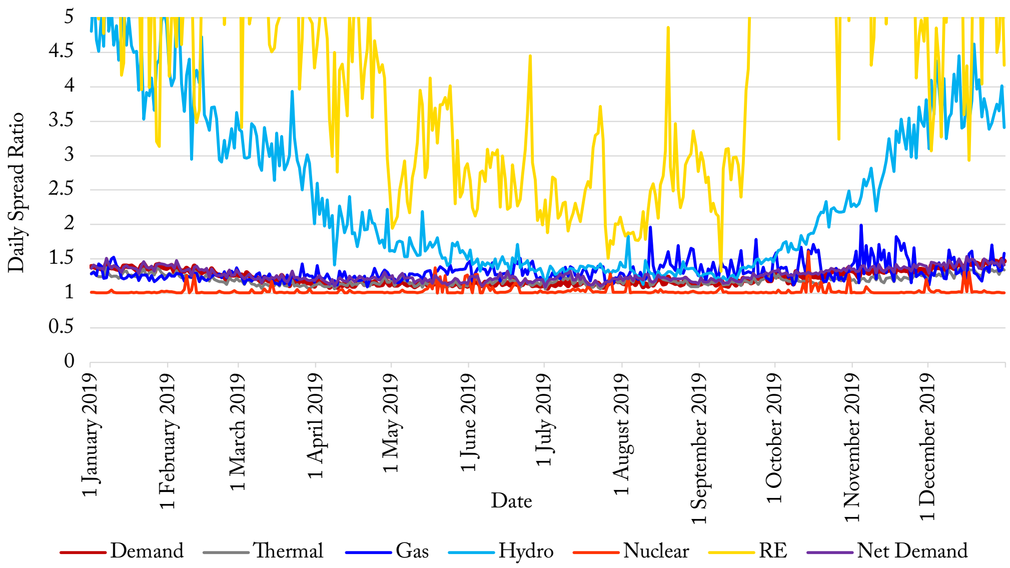
Figure 16: Daily Spread of Supply and Demand (ratio of maximum to minimum) (2019)



Source: Authors' analysis.

Given that it is very hard visualise the details for other fuels because of the wide range across fuels, we can expand the graph by clipping the y-axis like in Figure 17. We now see that post-monsoon gas swings much more specifically when RE has higher swings. Such compensation shows the value of gas seasonally, even with modest overall volumes; correlation data do not show this as starkly. Importantly, net demand has a higher daily spread than demand for most of the time periods. Demand itself lowers its daily spread mid-year, likely due to air-conditioner usage (which raises night-time demand, which would otherwise be the daily low).

Figure 17: Zoomed View of Daily Spread of Supply and Demand (ratio of maximum to minimum) for 2019



Source: Authors' analysis.

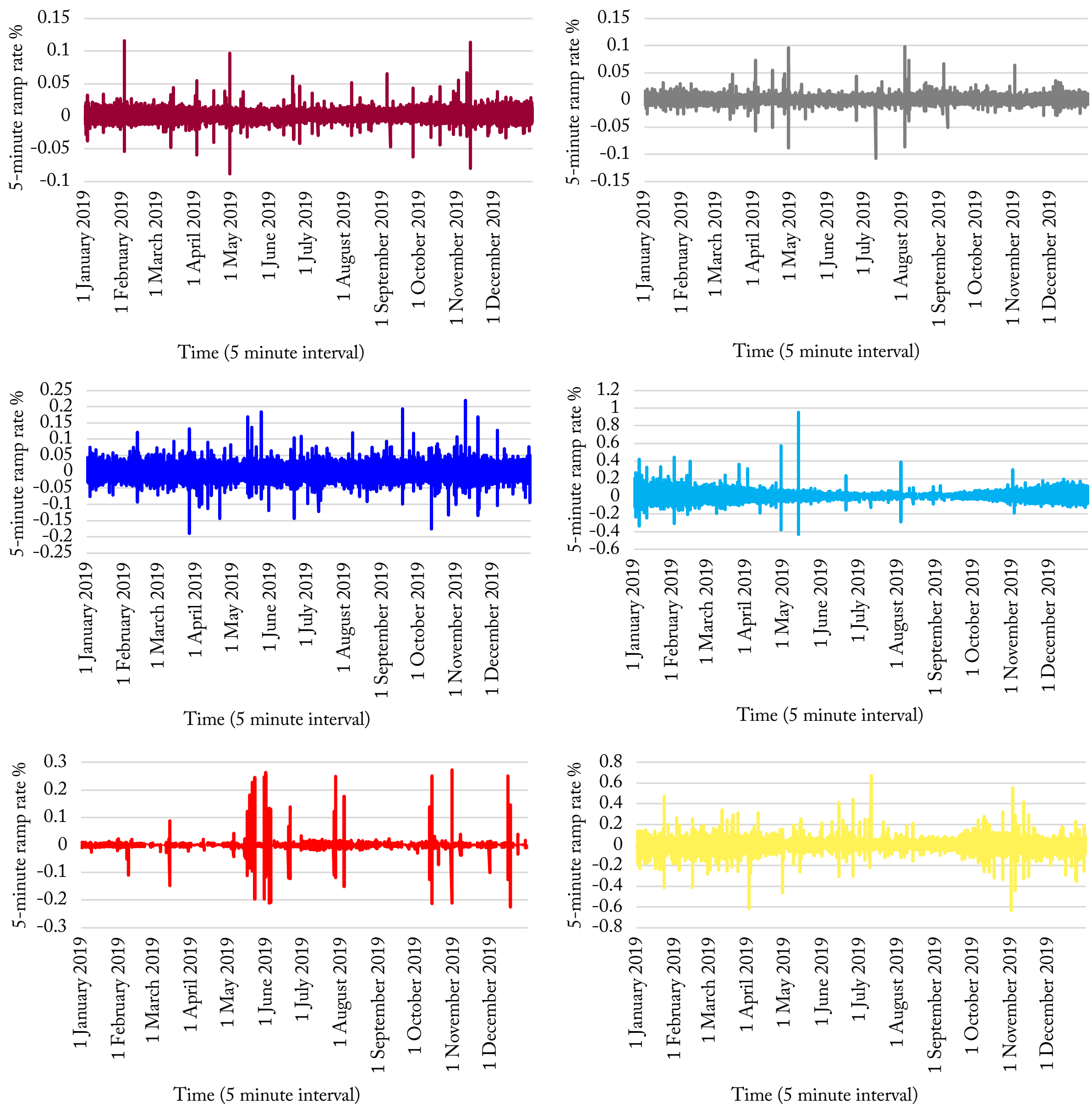
Balancing Requirements through Swings (and Ramps) in Supply

A fuel's ramp rate is another important metric for grid design, which influences policy. For example, a fuel that is otherwise cheaper may not suffice for grid balancing if it cannot change output fast enough. As of 2019, as we've seen, ramping has been disproportionally done by hydropower and coal—the latter because of its large base more than its ramp rate (percentage ramp per minute) capabilities.

On the supply side, there are strict limits on how fast a dispatchable source can increase supply. For a single coal power plant, most plants limit to 1% per minute thermal ramp limit, a figure of merit discussed in POSOCO (2020), even though theory and norms say they should handle up to 3% per minute for brief periods. This is at a plant level, and national aggregate ramps would end up being lower because of coordination and signalling issues.

Figure 18 shows the percentage ramp rates for demand in 2019, and all five fuel types over a five-minute interval; we ignore spikes assuming those are outliers not caught by our corrective algorithms.

Figure 18: Percentage Ramp Rates for Demand (maroon), Thermal (gray), Gas (dark blue), Hydro (light blue), Nuclear (red) and RE (yellow)



Source: Authors' analysis.

A few points stand out from the graphs.

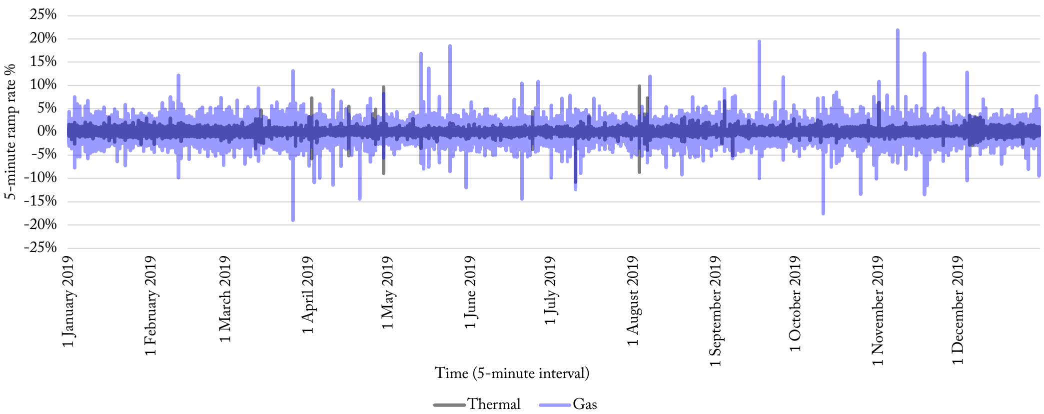
1. Demand typically changes by under 2% in any five-minute block, except a few data points which might be outliers. This corresponds to under 0.5%/minute.
2. Coal has similar ramp rates, but slightly lower than demand for almost all the time blocks.
3. Gas has a higher ramp rate, close to 5% per five-minute block, across much of the year.
4. Hydropower has dramatically higher ramp rates approaching 4%/minute during the winter, but the ramp rate declines in the middle of the year. This emphasises the point that hydropower isn't always controllable or a means of "free storage".
5. Nuclear power is relatively flat, where most changes are likely based on plants going online or offline (such as for fuelling or maintenance reasons).
6. Subject to data limitations, RE appears to have a high volatility (we cannot call it purposeful ramping), over 10% per five-minutes in many cases. *These are non-controllable, except to the extent we curtail RE if required.*

In the short run, there appears to be modest headroom to meet demand ramp swings through the combination of supply options, but we know that hydro is not rising as fast as RE (or demand) is growing. Rising RE can make net demand ramping requirements worse as we've seen.

The good news is that even if we attempt to scale the ramping from thermal plants with the rise in RE, say, considering five times more RE for the same coal capacity, with five times the up-ramping from today, we would be within the specified 1% per minute thermal ramping limits for 99% of the time. However, such operations, even if technically feasible, have economic impacts both due to wear and tear as well as a fall in efficiency. Current contracting frameworks do not compensate sufficiently for these effects. The CERC (2016) has notified degradation of efficiency (station heat rate) and auxiliary energy consumption by operating at part load, but these are more applicable for steady-state or at least gradual operations.

We note that while the percentage ramps by gas are higher than for coal (Figure 19), given the 20+ times differential in coal capacity operating at any time compared to gas, the absolute ramping support given by coal in MW/minute is far higher than by gas (Figure 20). This doesn't diminish gas' value, especially for more sudden spikes (given it can do much faster ramps than coal), and more so in a very high RE future, but it emphasises the value that coal also provides. It also limits the value of needing more gas capacity for higher RE—in the visible future coal can suffice for the most part, and even gas output is low compared to its installed capacity (due to lack of affordable and secure fuel).

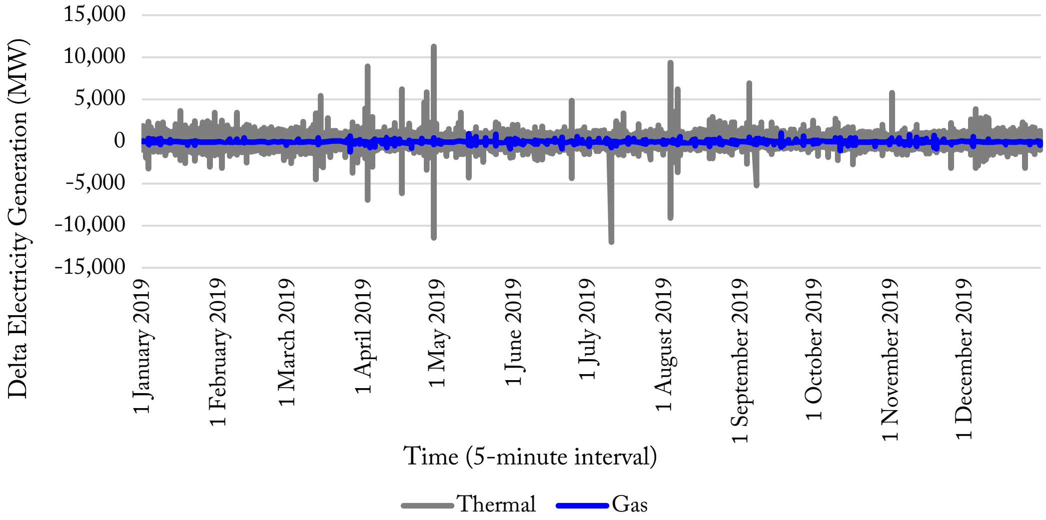
Figure 19: Five-minute Ramp Rate% for Thermal vs Gas (2019)



Note: Thermal is shown as under the gas and isn't always visible as a distinct colour. It occasionally does ramp higher percentage-wise, but some of these might be outliers or errors for thermal data.

Source: Authors' analysis.

Figure 20: Five-minute Absolute Ramping by Thermal versus Gas (2019)

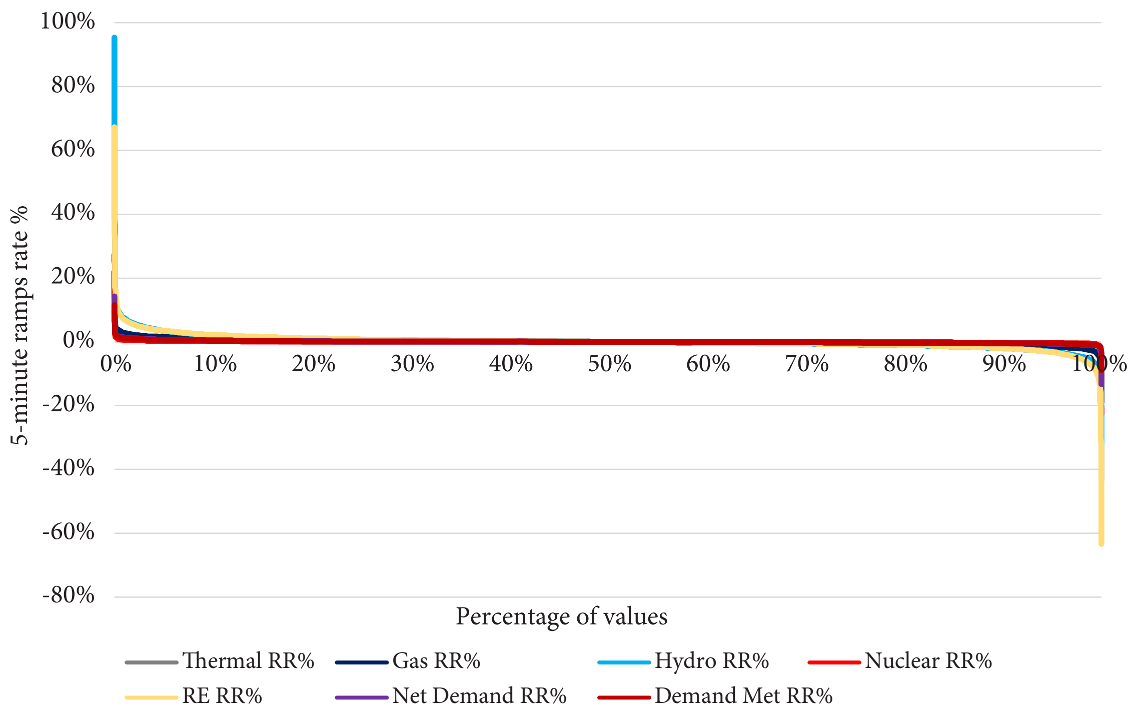


Source: Authors' analysis.

To understand outliers for ramping, we can stack (order) the ramping instead of viewing the ramping chronologically.

Figure 21 below shows the stacked ramping rates (five-minute percentage) across all supply, demand, and net demand. Because of either outliers or extreme values, it is hard to identify trends except to note that extreme outliers are only with RE and hydro. A zoomed-in look at the stacked ramp rates, excluding the extreme cases, gives a clearer picture on the ramp rate trends across all the sources of electricity, net demand and demand met. Figure 22 shows stacked ramp rates between the ±10% bracket.

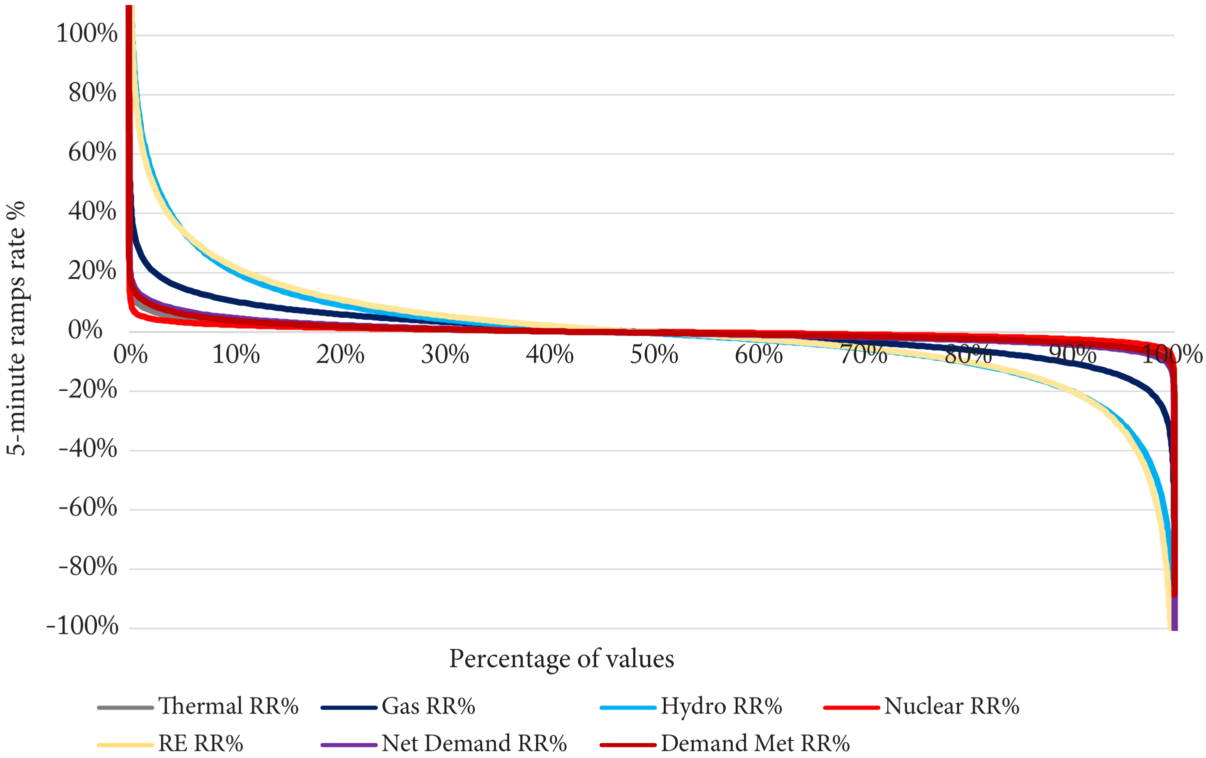
Figure 21: Stacked Five-minute Ramp Rate % (2019), across Fuels, Demand and Net Demand



Note: These stacked graphs are post-manual correction of a handful of outliers per curve.

Source: Authors' analysis.

Figure 22: Stacked Five-minute Ramp Rate % (2019) across Fuels, Demand, and Net Demand—Zoomed to Cap Ramping at 10%



Source: Authors' analysis.

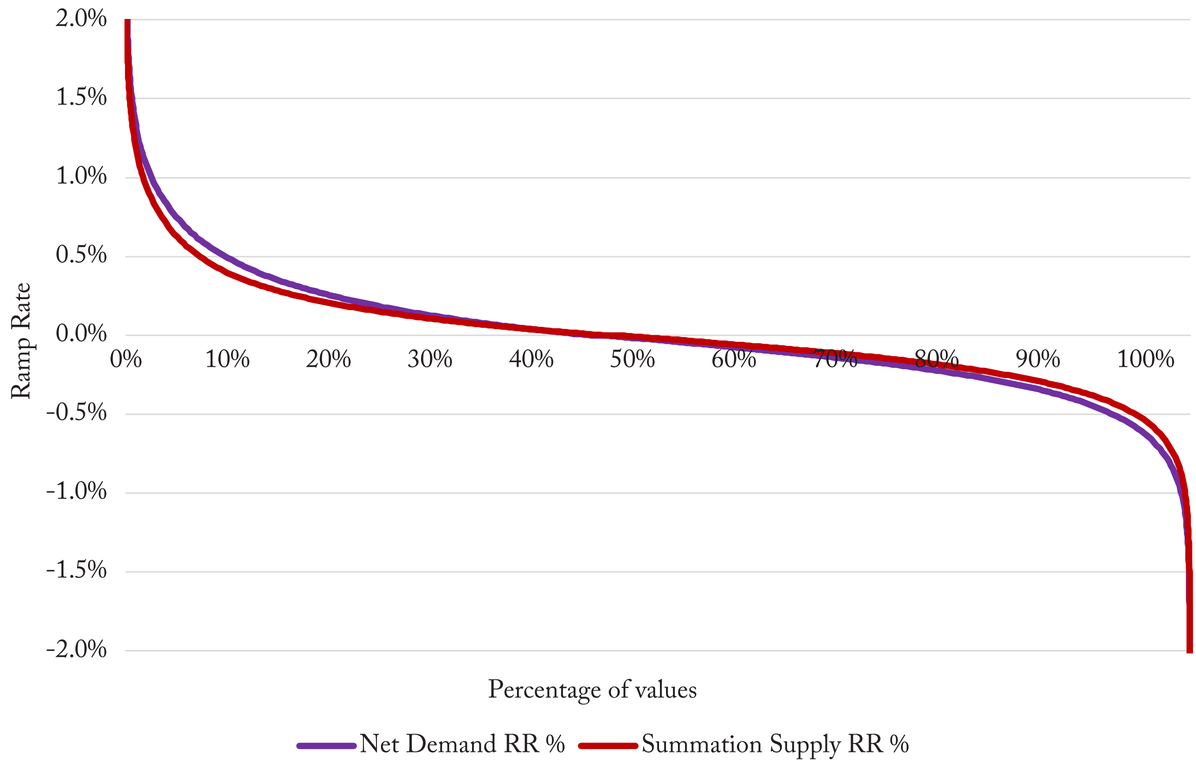
Figure 22 shows, e.g., even hydro doesn't ramp more than ~2% per minutes for 80% of the time (stacked between 10% and 90%. Such graphs help planning by determining how much fast ramping capacity might be needed, and for what duration.

By zooming in we can now see the following (recall, these are not chronologically linked, just individually ordered from high to low respective ramps).

1. The highest ramping in percentage is from renewables and hydro. The former is uncontrollable, and is often negatively correlated with demand, which is bad for grid management, while hydro is the best fuel for grid balancing. Unfortunately, the growth rate of hydro capacity is much, much lower than that of RE, especially as visible through 2030.
2. The next highest ramping in percentage comes from natural gas, which is considered a nimble fuel.
3. Ramp rates of demand and net demand are modest. However, in the future, when higher ramp-rate-capable dispatchable (firm) power growth is limited (with a rise in RE), meeting demand ramps may be difficult.
4. The lowest ramping in percentage comes from thermal and then nuclear. Nuclear is considered an inflexible fuel, non-responsive to demand swings (or net demand swings).
5. The positive and negative ramp rates for fuel supply are relatively similar, implying ramp-up and ramp-down capabilities of supplies are important. Renewable energy is one-sided in that it can be disconnected (curtailed, or thrown away) in case it is surplus, a likely scenario with rising RE for parts of the year. It will happen if there isn't any alternate which can back down. Such curtailment raises the costs of RE, but RE should still remain cost-effective for modest levels of curtailment (Tongia, 2022).

Importantly, Figure 23 shows that the ramping for net demand is greater than for demand, which means that adding RE *to the mix makes balancing and ramping worse for the grid*. This was seen through the correlations between RE and demand as well. While the impact isn't very large yet, it would likely sharpen as RE rises. Another feature of interest is that the up-ramp and down-ramp for demand and net demand aren't symmetric—the cross-over is about 45:55. *What this specifically means is we have slightly fewer, but sharper, up-ramps than down-ramps for demand and net demand.* As the graph shows, 10% of steepest demand up-ramps correspond to a threshold of just under 0.5% ramping in five minutes, while for down-ramps, the worst 10% correspond to close to 0.45% ramping in five minutes. This would also worsen as RE rises.

Figure 23: Five-minute Ramp Rate (RR) % for Demand versus Net Demand (2019)



Source: Authors' analysis.

If we examine RE, an important caveat is that this analysis—even ignoring missing data, or the fact that this doesn't separate wind and solar—is only applicable for 2019. We do not know year-on-year variations, which can be very high for wind (Schwarz and Tongia, 2023, showed this for Karnataka), and the supply curves are based only on existing installed technologies. Newer solar has a higher CUF (also dubbed PLF) with a flatter daytime profile (due to direct current to alternate current oversizing), and new wind turbines are very high hub-heights, raising average CUFs measurably.

Policy Implications and Discussion

The carbon tracker and similar tools are important for policy-makers and system planners as we move away from an energy (kWh) focus to one that focuses on capacity (kW) at the right time (and the right place). This will enhance system planning, and also should feed back into pricing frameworks for electricity.

While we only show a snapshot of one year, 2019. As 2020 onwards through early 2022 data are going to be misleading due to the shocks of COVID-19 and the recovery, we cannot show multi-year time series data. This analysis shows insights not just for a grid moving towards high RE, but it also shows specifics that must be included in any future planning scenarios.

Time-of-day analysis remains critical, and this must go down to the state level, which is the typical level of grid operations and dispatch (regional dispatch for some central generation notwithstanding). Compiling from state to aggregated national is only mechanistic as long as one assumes zero inter-state transmission constraints, and proper grid dispatch.

A few of the key findings.

1. *Thermal and hydro play outsized roles in balancing*. The latter is especially flexible, but growing at a much lower rate than RE in terms of capacity addition.
2. While natural gas has a high ramping *rate*, its contribution overall is low because of the small base in operation.
3. The real need is not just meeting demand but meeting net demand, which is defined as demand minus RE (in arithmetic terms, treating RE supply as negative demand). For 2019, adding RE increased the ramping of net demand compared to demand. This means higher RE increases the ramping burden on other sources of supply.
4. Renewable energy's contribution to net demand is lower at periods of high net demand, especially the evening peak. This emphasises the limits of solar power from a system perspective, even if it is inexpensive and can be integrated relatively easily.
5. Seasonal and time-of-day differences are critical to understanding the relative contributions of different supply options (and even demand variability). These will have to propagate into pricing signals.

While the paper has highlighted a number of trends, and sets the stage for multi-year analysis, key questions that follow from this analysis and that need addressing include:

1. How will RE be integrated as its share rises? (Given the data are all-India, the state-level situation will be tighter, unless we assume "infinite" and perfect transmission.). One major challenge is we don't know the details of future deployment, not just wind versus solar or location, but even whether RE will grow linearly, exponentially, or in-between.
2. Can coal plants lower their output enough to allow RE mid-day, yet meet peak evening demand? The corollary becomes how much will RE have to be curtailed (which raises its costs)?
3. At what point will storage technologies be required (rather, how much, by when)?
4. If hydro plays a key peaker (and ramping) role, given its growth rate is low, what could supplant hydro going forward?
5. What is the expected volatility of both demand and RE and hydro year-on-year? This is a critical issue that our data cannot answer alone since we do not have sufficient years of data at carbontracker.in.
6. How does the national picture map to state-level operations? We need similarly granular data at each state-level for future studies.
7. Given rising RE will create a higher ramping burden on the rest of the grid, what are new compensation mechanisms required for such services. Today, ancillary services in India focus on frequency support, but policies have been limited in how they incentivise or even allow different technologies to operate for grid supporting ancillary services.
8. What is the interplay of seasonality with daily variations from both a demand and supply perspective? This will help define any required 'over-engineering' from a capacity perspective, or storage technology sizing. Older norms of buffers (like the grid code requirement for 5% surplus capacity) may need to be updated for a future with higher RE.

9. What data are (or aren't) captured in time-of-data figures, like via load dispatch centres or MERIT? We know that today all RE is bundled together, while we would want to know the split between wind, solar, and other RE (and also ensure full coverage of RE plants). A more subtle issue is these data are typically from grid operators, and inherently miss data on distributed energy resources (DERs) and small generators. As rooftop solar rises, this becomes critical for grid planning, not just for national or state balancing but also for discom planning, including at the local level when they will have to manage reverse flows from the edge.

One of the insights from the analysis is that balancing (absolute correlations) and ramping (correlations across swings) aren't necessarily linked, especially for hydro, which is positively correlated with load but much more highly correlated with incremental (Δ) generation, more so in the peak times of day.

At a policy level, we must stop valuing and pricing electricity at an average basis, using LCOE. It is well known that as the share of RE rises, its marginal value declines and its marginal cost of integration rises. With very high RE scenarios, we are staring at either curtailment of RE or paying the premium for storage (or both).

Though 2019 had negligible storage at a grid level, it may grow in India. The first uses of storage will not be for bulk supply time-shifting but rather for higher value uses like ancillary services and ramping support. However, over time bulk storage will become more important. Not only do we need policy clarity on storage (is it a generator or a consumer of power or both?), we need to include details on storage in national energy accounting, including in the MERIT portal. While the MERIT portal could easily capture when storage feeds in as supply, it's much harder to capture what fuel charged the battery. A linked and more pressing need is for data to break down instant RE output across wind, solar, and other RE; the government's MERIT portal doesn't do so.

A specific need for going beyond average costs (LCOE) is to consider capacity value. Some countries do this through capacity markets, but even without this, regulators should capture the value of avoided capital expenditure, especially for new supply that may operate infrequently, as a peaker. Load duration curves that stack supply (like visible on carbontracker.in) emphasise peakiness of demand and net demand. Such curves show that about 6.5 GW of thermal operates only 1% of the time. Of course, this is an aggregate, and is spread out across the year.

As India considers a very high-RE future, more care will have to be taken in choosing which type of RE (wind and solar) is placed where; even without a breakdown, our data show differences by time of day. Locational issues will also need to examined (wind is much more location specific, and wind profiles vary by region). A subtle new system design would value peak RE (in terms of net demand) more than average RE, which might mean siting wind at a different location than would merely maximise total generation.

Time-of-day pricing will become necessary at some point, and this has two sides. For procurement, on the supply (wholesale) side, we have to obviously move beyond LCOE. On the retail side, consumers should also see signals for time-of-day prices, especially to help avoid peak demand but also to coincide with cleaner energy. Any concerns over complexity or regressive impacts on some consumers can be handled through aggregations or new instruments, but there will need to be investments in appropriate metering technology. This was already announced as part of government support, e.g., in Finance Minister's 2021–2022 Budget speech (Sitharaman, 2021).

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Appendices

Correlation Tables

Table A1: Annual Delta Correlations Broken into Seasons and Times-of-Day for 2019

ΔTHERMAL											
Correlated to Total Supply	Winter	Summer	Monsoon	Post-Monsoon	Annual by ToD	Correlated to Net Demand	Winter	Summer	Monsoon	Post-Monsoon	Annual by ToD
Morning	0.783	0.649	0.497	0.721	0.716	Morning	0.783	0.679	0.849	0.721	0.780
Mid-day	0.675	0.783	0.533	0.563	0.664	Mid-day	0.630	0.766	0.565	0.603	0.662
Late Afternoon	0.539	0.722	0.395	0.654	0.578	Late Afternoon	0.405	0.636	0.460	0.707	0.537
Evening	0.726	0.762	0.810	0.864	0.815	Evening	0.697	0.744	0.759	0.840	0.791
Night	0.901	0.795	0.621	0.815	0.822	Night	0.864	0.709	0.646	0.824	0.787
All day by season	0.794	0.705	0.572	0.751	0.715	All day by season	0.736	0.711	0.685	0.777	0.726

ΔGAS											
Correlated to Total Supply	Winter	Summer	Monsoon	Post-Monsoon	Annual by ToD	Correlated to Net Demand	Winter	Summer	Monsoon	Post-Monsoon	Annual by ToD
Morning	0.276	0.222	0.220	0.222	0.258	Morning	0.279	0.233	0.326	0.214	0.278
Mid-day	0.204	0.170	0.109	0.135	0.160	Mid-day	0.188	0.160	0.121	0.141	0.159
Late Afternoon	0.110	-0.004	0.087	0.229	0.116	Late Afternoon	0.118	-0.008	0.276	0.258	0.170
Evening	0.243	0.251	0.297	0.466	0.355	Evening	0.249	0.233	0.294	0.476	0.357
Night	0.169	0.160	0.208	0.225	0.194	Night	0.184	0.157	0.252	0.208	0.195
All day by season	0.244	0.171	0.216	0.299	0.230	All day by season	0.245	0.161	0.284	0.319	0.250

ΔHYDRO											
Correlated to Total Supply	Winter	Summer	Monsoon	Post-Monsoon	Annual by ToD	Correlated to Net Demand	Winter	Summer	Monsoon	Post-Monsoon	Annual by ToD
Morning	0.795	0.685	0.481	0.767	0.707	Morning	0.788	0.716	0.665	0.759	0.727
Mid-day	0.473	0.453	0.438	0.405	0.459	Mid-day	0.659	0.523	0.374	0.629	0.566
Late Afternoon	0.576	0.335	0.208	0.712	0.475	Late Afternoon	0.629	0.559	0.129	0.743	0.584
Evening	0.791	0.760	0.730	0.842	0.792	Evening	0.765	0.776	0.718	0.802	0.778
Night	0.777	0.781	0.516	0.698	0.734	Night	0.766	0.701	0.563	0.784	0.718
All day by season	0.668	0.589	0.475	0.716	0.622	All day by season	0.760	0.681	0.513	0.780	0.704
ΔRE											
Correlated to Total Supply	Winter	Summer	Monsoon	Post-Monsoon	Annual by ToD	Correlated to Net Demand	Winter	Summer	Monsoon	Post-Monsoon	Annual by ToD
Morning	-0.217	0.148	0.332	-0.104	0.024	Morning	-0.590	-0.428	-0.682	-0.558	-0.540
Mid-day	0.482	0.474	0.715	0.571	0.555	Mid-day	-0.354	-0.131	-0.460	-0.417	-0.344
Late Afternoon	0.405	0.464	0.778	0.285	0.485	Late Afternoon	-0.483	-0.344	-0.474	-0.422	-0.430
Evening	-0.139	-0.018	0.311	-0.266	-0.032	Evening	-0.366	-0.401	-0.335	-0.391	-0.379
Night	0.146	0.154	0.609	0.147	0.253	Night	-0.020	-0.153	-0.454	-0.066	-0.186
All day by season	0.198	0.306	0.550	0.170	0.310	All day by season	-0.366	-0.345	-0.477	-0.420	-0.394

Table A2: Annual % Δ Correlations Broken into Seasons and Times-of-Day (ToD) for 2019

%Δ THERMAL											
Correlated to Total Supply	Winter	Summer	Monsoon	Post-Monsoon	Annual by ToD	Correlated to Net Demand	Winter	Summer	Monsoon	Post-Monsoon	Annual by ToD
Morning	0.801	0.653	0.510	0.720	0.718	Morning	0.792	0.682	0.847	0.708	0.780
Mid-day	0.678	0.785	0.535	0.551	0.656	Mid-day	0.628	0.762	0.570	0.607	0.656
Late Afternoon	0.549	0.718	0.383	0.658	0.577	Late Afternoon	0.417	0.644	0.477	0.705	0.555
Evening	0.740	0.769	0.824	0.853	0.820	Evening	0.708	0.739	0.770	0.831	0.796
Night	0.899	0.750	0.703	0.855	0.830	Night	0.859	0.720	0.640	0.827	0.811
All day by season	0.809	0.705	0.570	0.746	0.720	All day by season	0.748	0.718	0.686	0.772	0.731
%Δ GAS											
Correlated to Total Supply	Winter	Summer	Monsoon	Post-Monsoon	Annual by ToD	Correlated to Net Demand	Winter	Summer	Monsoon	Post-Monsoon	Annual by ToD
Morning	0.288	0.244	0.227	0.222	0.267	Morning	0.286	0.245	0.334	0.213	0.282
Mid-day	0.197	0.155	0.098	0.122	0.149	Mid-day	0.181	0.152	0.108	0.131	0.149
Late Afternoon	0.102	0.006	0.090	0.220	0.123	Late Afternoon	0.111	-0.005	0.270	0.238	0.167
Evening	0.247	0.251	0.303	0.436	0.351	Evening	0.251	0.235	0.299	0.445	0.353
Night	0.167	0.174	0.232	0.182	0.177	Night	0.181	0.152	0.242	0.190	0.174
All day by season	0.238	0.169	0.214	0.271	0.224	All day by season	0.239	0.156	0.275	0.288	0.224

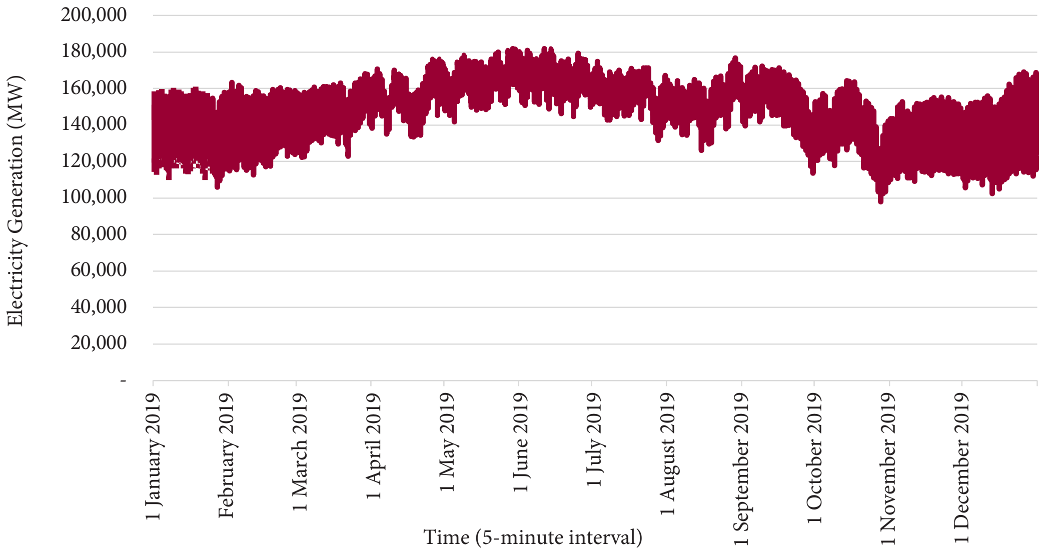
%Δ HYDRO											
Correlated to Total Supply	Winter	Summer	Monsoon	Post-Monsoon	Annual by ToD	Correlated to Net Demand	Winter	Summer	Monsoon	Post-Monsoon	Annual by ToD
Morning	0.790	0.658	0.473	0.738	0.692	Morning	0.779	0.710	0.646	0.720	0.689
Mid-day	0.491	0.465	0.465	0.398	0.449	Mid-day	0.628	0.532	0.346	0.623	0.541
Late Afternoon	0.503	0.369	0.191	0.662	0.440	Late Afternoon	0.565	0.547	0.095	0.702	0.535
Evening	0.785	0.765	0.714	0.783	0.766	Evening	0.758	0.784	0.698	0.747	0.750
Night	0.726	0.744	0.526	0.785	0.725	Night	0.726	0.708	0.536	0.771	0.696
All day by season	0.653	0.573	0.455	0.675	0.596	All day by season	0.727	0.663	0.466	0.743	0.658
%Δ RE											
Correlated to Total Supply	Winter	Summer	Monsoon	Post-Monsoon	Annual by ToD	Correlated to Net Demand	Winter	Summer	Monsoon	Post-Monsoon	Annual by ToD
Morning	-0.164	0.053	0.282	-0.053	-0.006	Morning	-0.473	-0.444	-0.608	-0.369	-0.420
Mid-day	0.492	0.453	0.708	0.568	0.535	Mid-day	-0.328	-0.131	-0.433	-0.422	-0.336
Late Afternoon	0.101	0.363	0.761	-0.093	0.124	Late Afternoon	-0.529	-0.328	-0.408	-0.540	-0.503
Evening	-0.059	-0.096	0.255	-0.191	-0.113	Evening	-0.259	-0.427	-0.324	-0.272	-0.352
Night	0.151	0.164	0.438	0.114	0.151	Night	0.008	-0.164	-0.429	-0.040	-0.125
All day by season	0.101	0.197	0.503	0.029	0.156	All day by season	-0.354	-0.367	-0.450	-0.424	-0.388

Supply and Demand Graphs for 2019

Figure 5 in the main text showed all of the supply types together, which makes it difficult to see individual variations due to scale differences. Figure 24 to Figure 31 show individual graphs for the year at five-minute resolutions (thus, 105,120 data points each), post manual correction of a few outliers,[12] *(about five to ten data points each).*

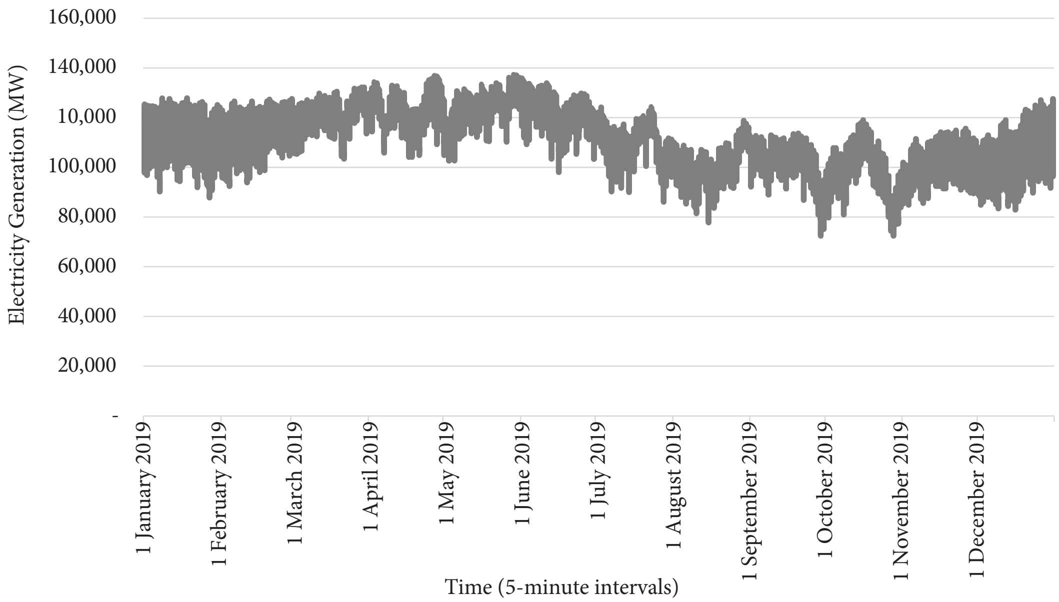
Seasonality is most pronounced for RE and hydro, and we also note the daily spreads (visible on these chronological graphs as roughly the vertical Y-axis direction) are very high for RE and hydro, more so in a relative sense.

Figure 24: Demand (load met) 2019



Source: Authors' analysis.

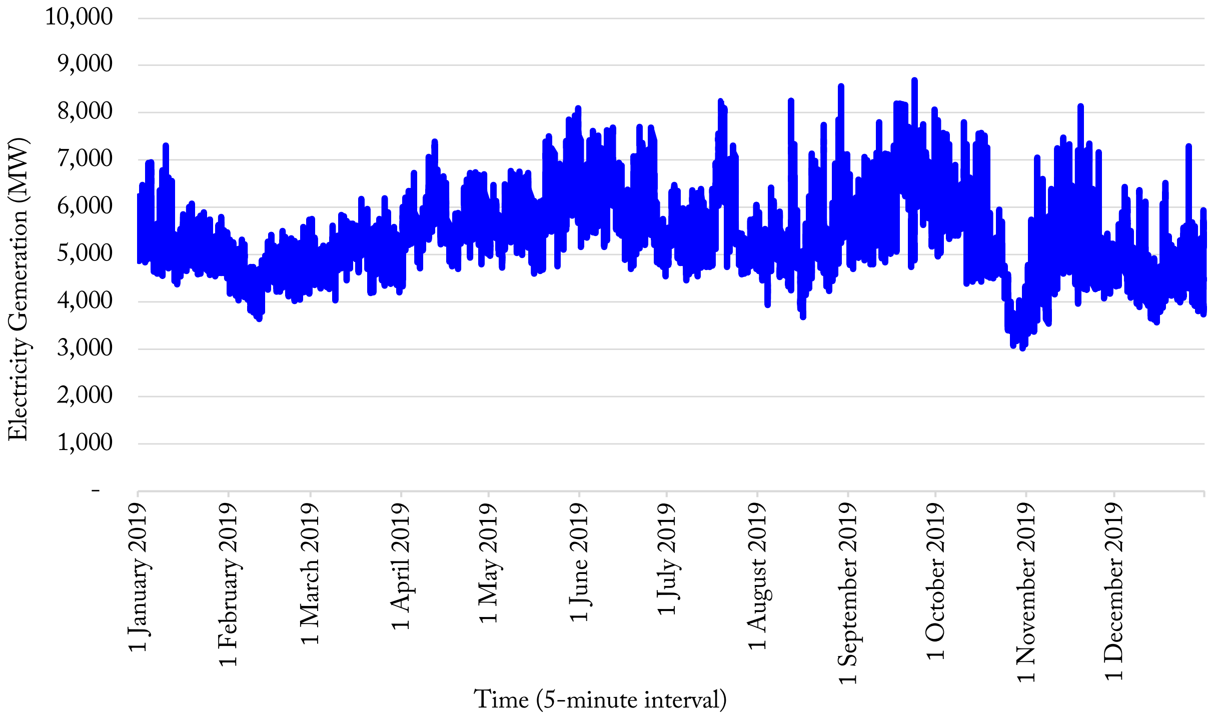
Figure 25: Thermal Supply (2019)



Source: Authors' analysis.

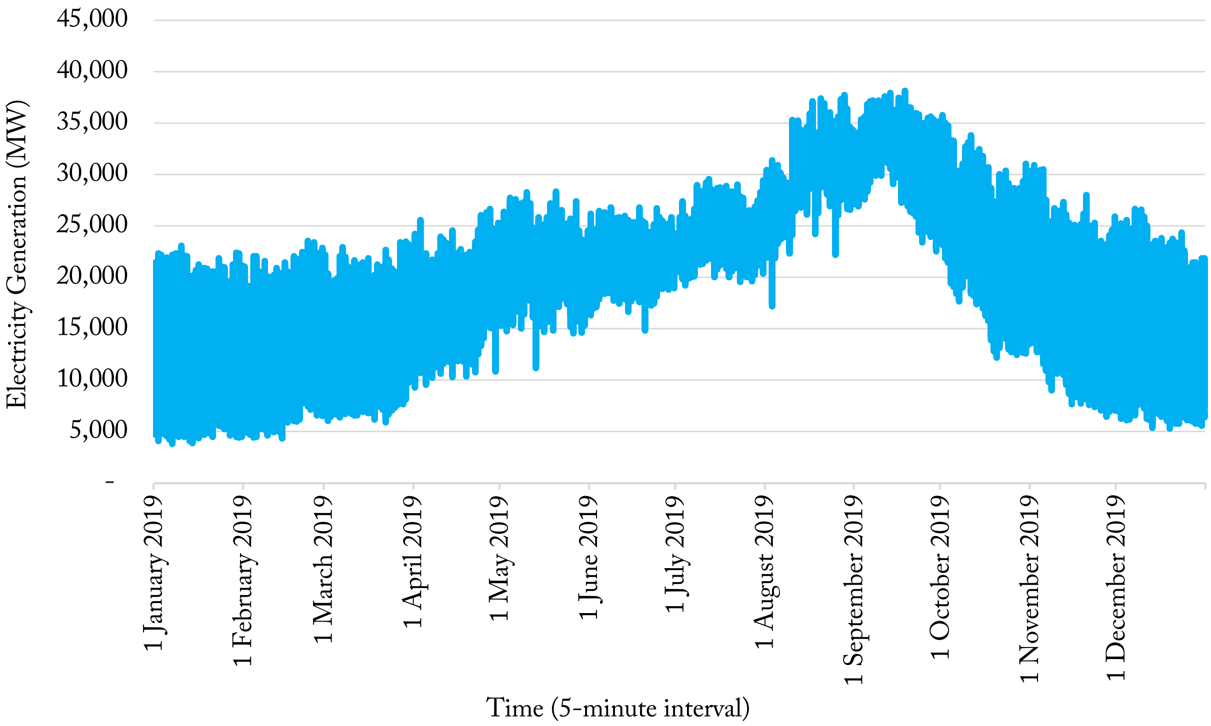
[12] These are outliers that the algorithmic correction doesn't capture, because they are technically possible, but post-facto analysis of how other sources behave indicate these are errors.

Figure 26: Gas Supply (2019)



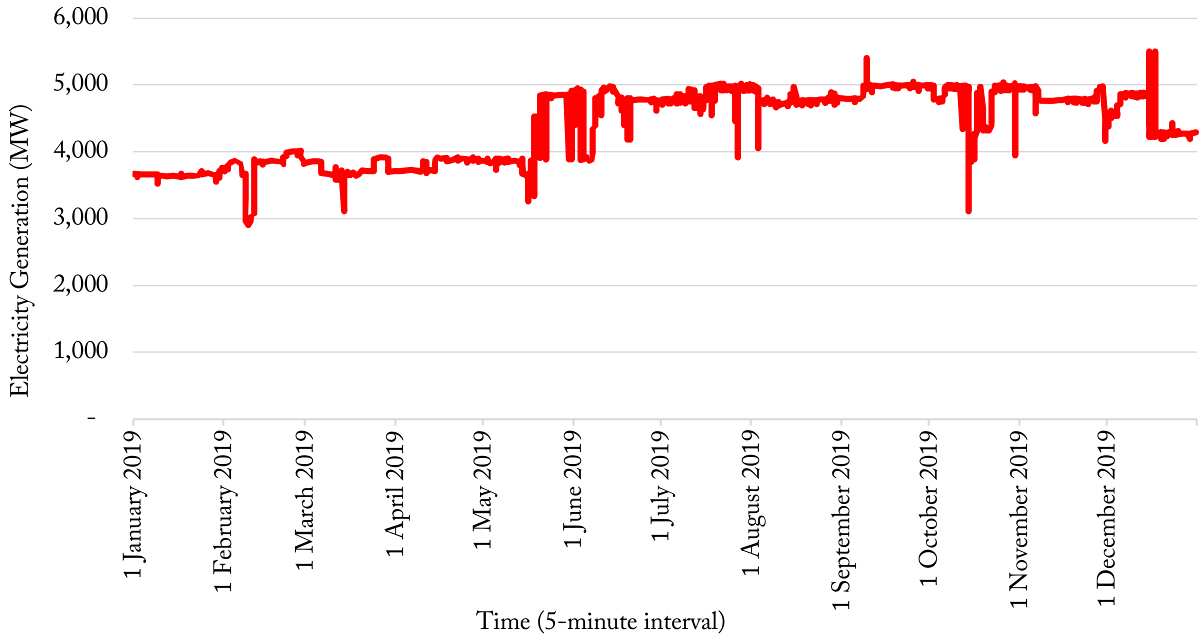
Source: Authors' analysis.

Figure 27: Hydro Supply (2019)



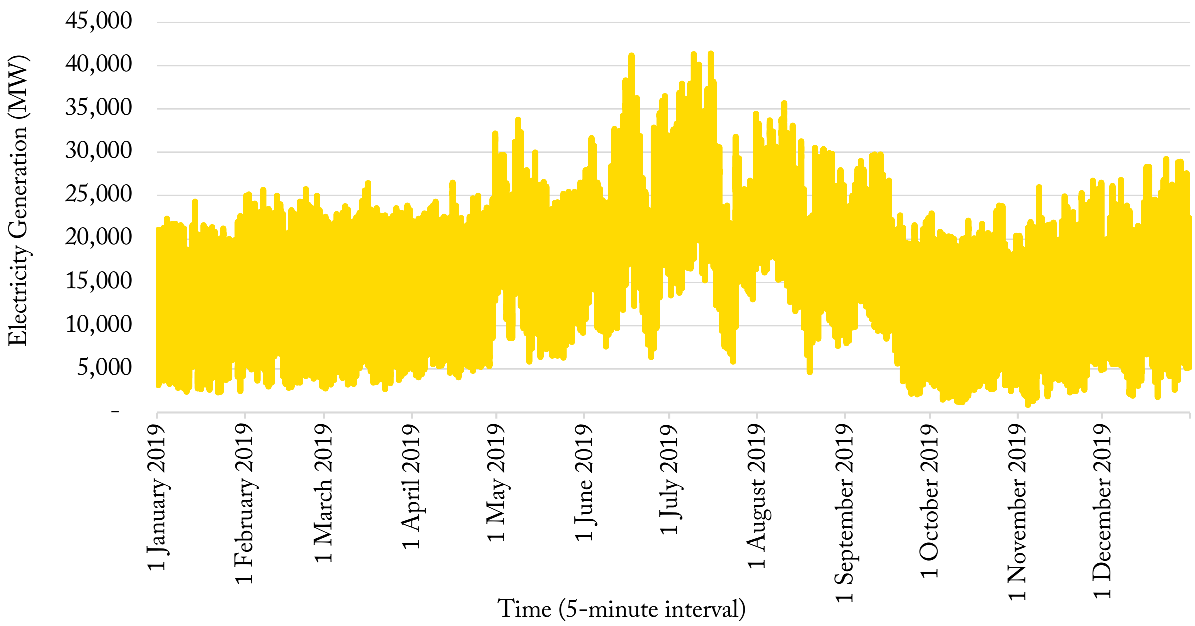
Source: Authors' analysis.

Figure 28: Nuclear Supply (2019)



Source: Authors' analysis.

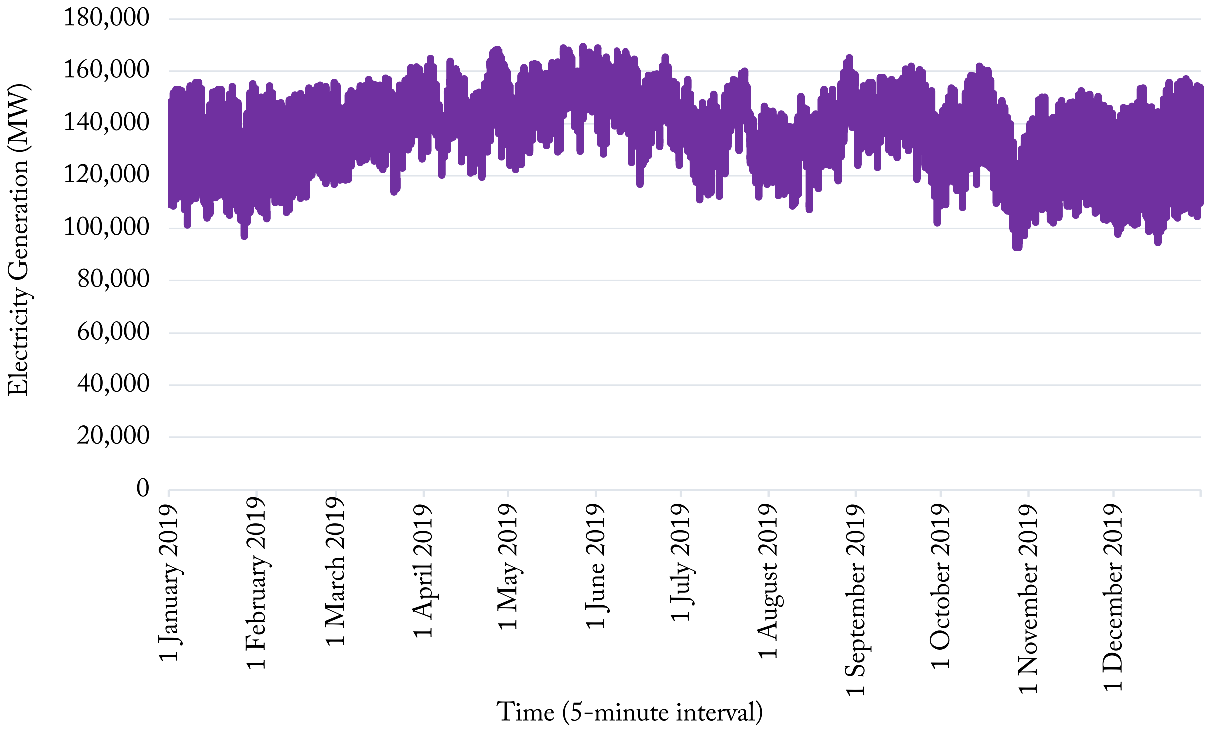
Figure 29: Renewable Energy Supply (2019)



Source: Authors' analysis.

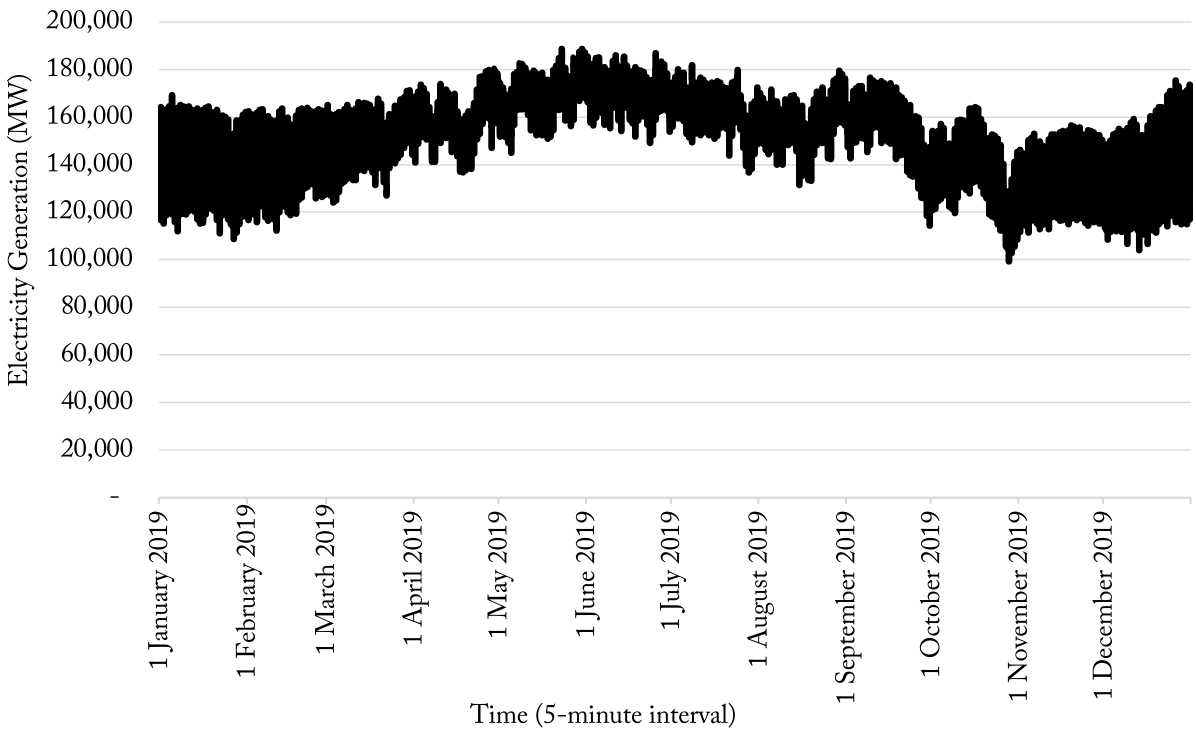
Notes: These are from MERIT India website data, and slightly under-report RE generation since not all RE is on the real-time SCADA system.

Figure 30: Net Demand (2019)



Source: Authors' analysis.

Figure 31: Summation Supply (2019)



Source: Authors' analysis.

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