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CONTENTS

LIST OF FIGURES

LIST OF TABLES

EXECUTIVE SUMMARY

Variable Renewables Create New Challenges for Operating and Planning the Power System

The power system must balance demand and supply at every location in the grid and at all times. In doing so, the power system already handles substantial variability, both on the demand side and the supply side. Demand changes over the course of the day; generating units experience technical faults; hydro output varies with the seasons, supply interruptions are witnessed due to sub-transmission and distribution outages, and so on. However, the introduction of the growing shares of variable renewable energies (VRE) such as wind and solar creates additional challenges for the power system. The power system needs to adapt to these new sources of variability, both in terms of short-term operations and longer-term system planning and investments.

Analysing Power System Operation in a High Degree of Technical, Temporal, and Spatial Granularity Is Crucial

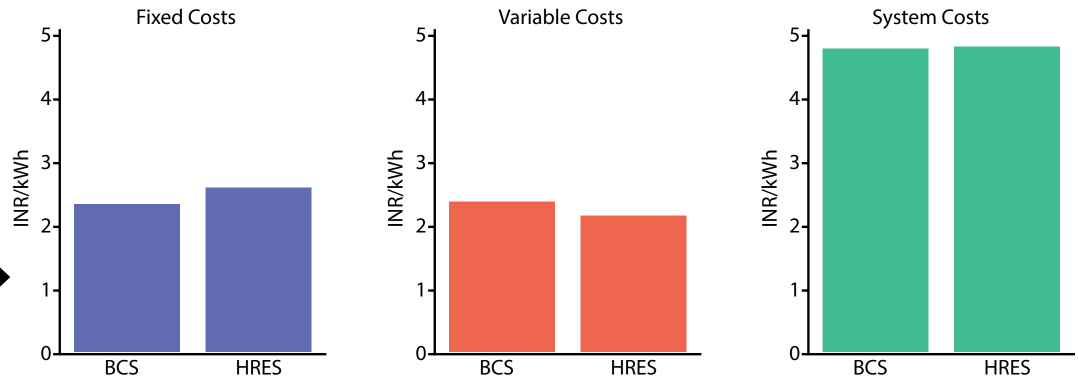
Generation from variable renewable energies can fluctuate on time scales of minutes or hours, as well as seasonally. The electricity generated from these plants is often far from centres of demand, meaning that power needs to be transmitted over long distances. Thus, as the shares of variable renewables increase, it becomes more and more important to analyse the operation of the power system at higher levels of temporal and spatial granularity: at least at the levels of hours and minutes, and states and regions. Likewise, the technical parameters of the generators in the system must be included in this analysis of power system operation: how fast they can ramp output up and down, how fast they can start from shutdown, and how much it costs to do so. With these objectives in mind, TERI has built a state-of-the-art power system operation model, which can simulate the operation of every generator in the Indian power system with a high degree of technical detail, for every hour or 15-minute block of the year, and with detailed representation of India's power grid.

India Can Integrate Large Shares of Variable Renewables at No Extra Cost by 2030

Using this model, TERI has studied possible pathways for the Indian power system to the year 2030. We explored two scenarios, both of which represent a step change in the levels of penetration of VRE compared to today's level. In the Baseline Capacity Scenario (BCS), the share of VRE in generation reaches 26% by 2030. In the High Renewable Energy Scenario (HRES), VRE reaches about 32% in total generation. If we include hydro, biomass, and nuclear, the share of zero-carbon sources of generation reaches 42% in the BCS, and 47% in the HRES. The total system-wide cost per unit is broadly comparable in both the scenarios, as the higher investment cost of more renewables is offset by a lower operational cost (Figure E1).

It should be noted here that our definition of system costs excludes the cost of transmission infrastructure. Likewise, system costs are not the same as customers' bills, which also take into account distribution infrastructure costs, various cross-subsidies between consumer categories, and so on. System costs are thus the total per unit costs of electricity generation, including sunk investment costs and variable fuel and start-up costs.

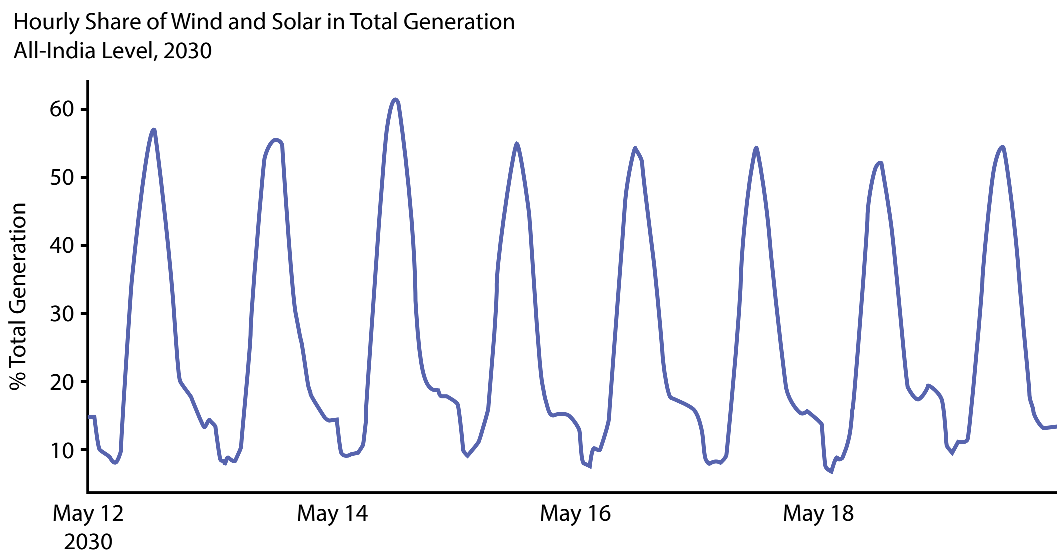
Figure E1: System Costs Are Essentially the Same between the BCS and HRES



Integrating This Level of Variable Renewables Is Feasible but Challenging

The variability introduced by this level of variable renewables is substantial. On most days of the year, wind and solar go from accounting for less than 15% of total generation in non-solar hours to more than 50% of generation in solar hours (see Figure E2). Accommodating this degree of variability is feasible but challenging. Aggregate indicators like the level of unserved load and

Figure E2: The Large Daily Variability of Solar Creates Substantial Challenges for the Grid Integration of Variable Renewables



curtailment of wind and solar are well within the acceptable bounds, in both our BCS and HRES.* In the BCS, the aggregate annual wind and solar curtailment amounts to 0.7% of total available wind and solar generation. In the HRES, the aggregate wind and solar curtailment rises to 4% in the absence of further measures to increase the flexibility of the power grid. Even 4% wind and solar curtailment may be acceptable, although there are a number of strategies that can decrease this level of curtailment.

A Step Change in the Flexibility of the Power System Is Required

To accommodate this high level of VRE, a step change in the flexibility of the power system is required. In the absence of this, India will simply not be able to achieve its 2030 objective of raising the generation capacity of renewables to 450 GW. It is time to shift the high-level focus of policy from the achievement of capacity targets to the transformation of the operations and investment in the power sector required to integrate VRE. Political engagement has pushed forward the achievement of significant capacity additions in renewables. The same is now required in order to increase the flexibility of the power system. Something of the nature of a 'National Power System Flexibility Mission' is the need of the hour, otherwise India's renewable energy ambitions will falter.

A Dramatic Scale-up in the Supply-side Flexibility from Coal and Hydro

In the mid-term to 2030, the majority of power system flexibility will need to come from the conventional generators, in particular the coal and hydro fleet. India has a substantial coal fleet, which, by varying its output across the course of the day, can provide significant flexibility to integrate VRE. Enhanced flexibility from the coal fleet can reduce the curtailment of wind and solar by more than 2 percentage points in the HRES. It is essential that the full coal fleet plays a role in providing flexibility to the power system, including the state-owned coal plants. But it is also potentially necessary to identify certain plants within the broader coal fleet that are required to meet more stringent flexibility requirements, for example achieving a technical minimum of 40% or even 30%, or two-shifting operation. In the HRES, more than 16 GW of coal plants are required for two-shift operations in the month of April. In the same scenario, more than 50% of days of the year see an aggregate all-India ramp requirement from the coal fleet in excess of 500 MW per minute, and 10% of days see a ramp requirement in excess of 700 MW per minute. This is a big technical and operational challenge.

Additional supply-side flexibility comes from the dispatchable hydro fleet, i.e. those plants with reservoir, pondage, or pumped storage. While the availability of hydro energy varies with the seasons, the analysis presented in this report is unequivocal: the integration of VRE requires that whatever hydro energy is available be dispatched flexibly within the day. Hydro energy provides peak support during the mornings and evenings and turns down essentially to zero at midday in order to support the injection of solar energy.

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* Unserved load is electricity demand that cannot be met due to technical constraints, such as the rate at which output can be increased from coal generators, for example. Curtailment refers to unused output from wind and solar that is wasted ('curtailed') because of technical limitations in the capacity of the power system to absorb more wind and solar at that particular time.

Battery Storage Supports Renewables and Reduces Operational Stress on the Rest of the Power System

In one of our HRES, we examine a substantial but feasible amount of battery storage by 2030, in order to explore its role in integrating variable renewables in India. The results are clear. Storage reduces wind and solar curtailment from 4% in the HRES without storage, to less than 0.2% in the HRES with battery storage. Operational stress on the rest of the system is also reduced. The required maximum coal capacities available for two-shifting operation in the HRES with storage are 50% less than in the HRES without battery storage. Likewise, the number of days with a maximum required ramp rate from the coal fleet in excess of 500 MW per minute falls from more than 50% to 32% in the two scenarios, respectively. In the mid-term, battery storage and coal flexibility are complementary, with batteries reducing the operational stress of the coal fleet. With the cost of battery technologies falling extremely rapidly and combined VRE and battery projects delivering competitive tariffs, it would be beneficial to define targets and policy frameworks for battery storage out to 2030.

One India, One Grid Is Essential for Integrating Variable Renewables

India's power system already benefits from the largest synchronous power grid in the world. The high level of interstate grid integration is driven by the strong presence of the federal level in India's power system value chain and policy and regulatory frameworks. The further development of this integrated grid is essential to increase the share of variable renewables. Shifting power from areas of excess renewables production to areas of high demand, and vice versa during times of deficit renewables production, is an essential strategy to drive greater penetrations of variable renewables. In our scenarios, high renewables regions and states, such as the Southern Region or Rajasthan, switch - often on a daily basis – from being power exporters to power importers, depending on the production of their renewable resources. The coal belt of the Eastern Region plays a crucial role too, supplying flexible coal generation to high renewable regions during times of low renewable production.

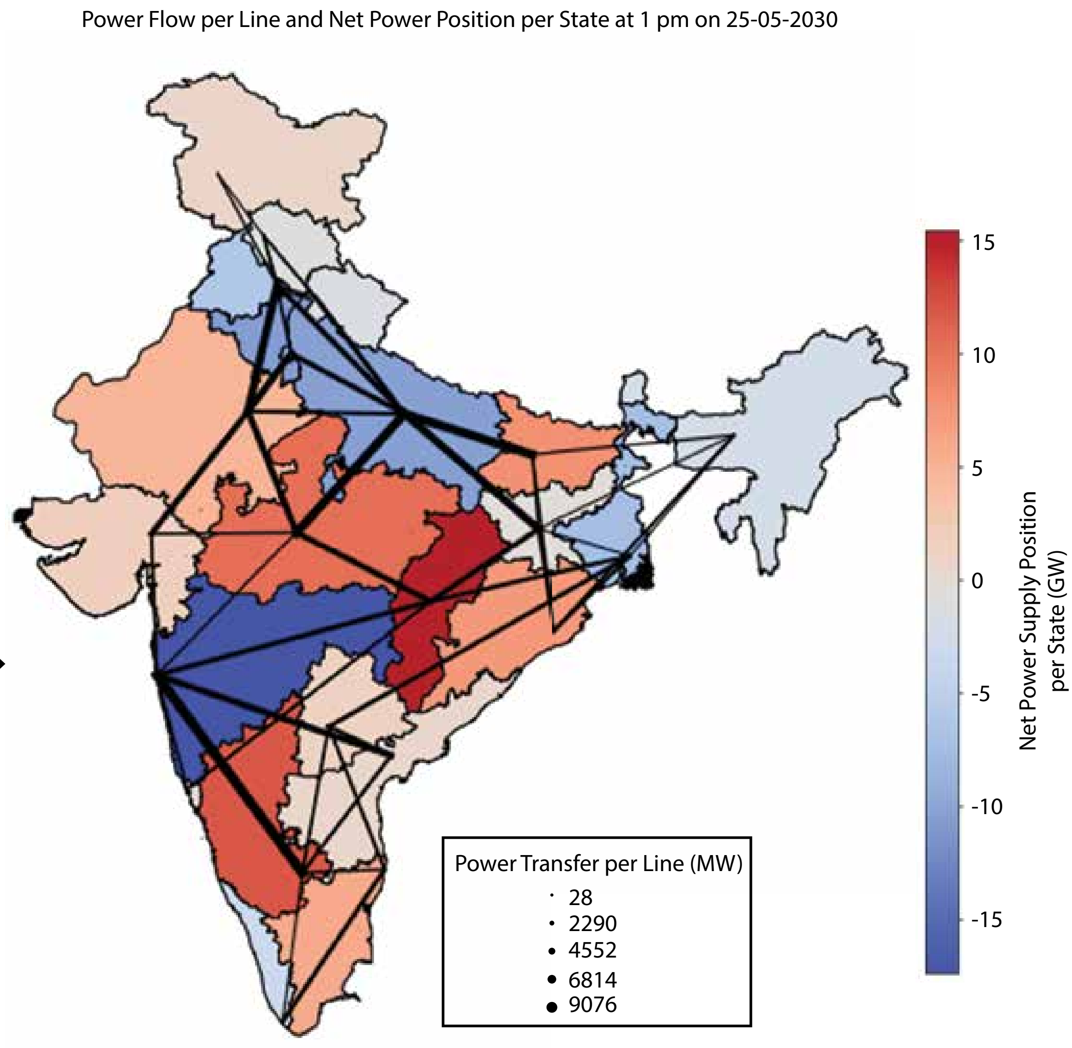

Figure E3: On a High Renewable Energy Production Hour, More than 40% of All-India Demand is Being Met from Interstate and Interregional Flows

We get a sense of the importance of interstate power transfers by examining what occurs on the Indian grid during a high renewable energy hour in 2030, according to our modelling analysis (Figure E3). At this hour, with solar injection at its maximum, more than 40% of total Indian electricity demand is being met by electricity that crosses an interstate border. Achieving this degree of grid integration is much more than an issue of just transmission. It requires coordinated scheduling and dispatch of supply resources at the regional and national levels, and efficient electricity markets to coordinate demand and supply, and provide the price signals necessary for such a flexible operation. Developing the regulatory, market, and operational 'infrastructure' is the need of the hour. One India, One Grid has already been achieved, but the degree of integration of this grid will need to grow in order to meet India's renewable energy ambitions.

Conclusion and Recommendations

This report has charted a cost-effective and feasible pathway for India's power system to achieve high levels of wind and solar electricity generation by 2030. Under this scenario, additional investment in coal-fired power beyond the current pipeline would be neither necessary from a system adequacy point of view nor financially justified, given the rapid cost declines in renewables plus storage and broader grid integration strategies. This would put India's power system on a pathway to almost zero emissions by 2050. The analysis presented in this report demonstrates that such a pathway is both technically feasible and economically affordable. However, the challenge is considerable. India's power system has many advantages and many achievements already, not least its huge and integrated grid. But more than the achievement of renewable capacity addition targets, the focus of policy and regulation should shift to how to make the Indian power system more flexible and fit for purpose in the new paradigm of increasing shares of variable renewables.

01 INTRODUCTION AND POLICY CONTEXT

Providing affordable and reliable electricity is essential to the achievement of India's goals of socio-economic development. Tremendous progress has been made in village and household electrification and reducing the previously endemic peak power and energy deficits. At the same time, the electricity sector is responsible for the largest share of India's energy-related CO_2 emissions (43.4% as of 2018). This is due to the dominance of coal in India's electricity mix, which accounted for 73.1% of total electricity generation in 2018. Hydroelectricity came in a distant second at 9.3% of electricity generation, and wind and solar accounted for just 6.1%.[1]

In light of the negative environmental effects of coal-based electricity generation, the Government of India has launched a number of initiatives to increase the share of clean technologies in the electricity sector. Central among them is the goal of achieving 175 GW of installed capacity of renewable energy in the power sector by 2022. In addition, the Government of India has mooted a target of 450 GW of renewable energy generation capacity by 2030. This number has been mentioned in a report studying the 2030 capacity mix by the Central Electricity Authority (CEA), and reiterated by Prime Minister Shri Narendra Modi in his speech at the UN Secretary General's Climate Action Summit in September 2019, although without mentioning the date.[2]

Increasing the share of variable renewable energy (VRE), such as wind and solar, in the electricity mix brings additional challenges of grid integration, i.e. the balancing of the variability of VRE on different timescales. The power system has always been faced with variability, both on the demand and supply sides. But the introduction of VRE creates additional challenges.

The grid integration challenge for India has been studied in-depth with respect to the 2022 target of 175 GW.[3] However, the grid integration aspects of mid-term targets to 2030 have not been the focus of sufficient study. In this context, this study contributes a detailed analysis of the operation of the power system in 2030 under different scenarios for production capacities, supply-side flexibility, storage, and transmission. The primary objective is to outline what is required to take the share of VRE to levels greater than 30% of generation by 2030, and the share of zero carbon generation (i.e. VRE plus nuclear, biomass, and hydro) to greater than 40%. If this is achieved, the electricity sector would be on a pathway to very low emissions by 2050.

It is important to stress that this study is part of an ongoing effort to strengthen the analytical capability of players within the Indian power sector, including at central and state levels. The increasing penetrations of VRE, uncertainty in load growth and load profiles in the future, and disruptive players like electric vehicles or distributed energy resources raise the bar in terms of

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[1] Data from Enerdata. 2020. Global Energy & CO2 Database. https://www.enerdata.net/services.html

[2] See CEA. 2019. Draft Report on Optimal Capacity Mix for 2029-30. New Delhi: Central Electricity Authority, Ministry of Power, Government of India. Details available at http://cea.nic.in/reports/others/planning/irp/Optimal_mix_report_2029-30_FINAL.pdf . The Union Minister of Power, Mr. R.K. Singh, has also affirmed that the 450 GW target for renewables expansion pertains to 2030. See: https://www.livemint.com/politics/policy/india-confident-of-adding-450-gw-of-renewables-by-2030-raj-kumar-singh-11571137804129.html

[3] See NREL, LBNL, POSOCO, USAID. 2017. *Greening the Grid: Pathways to Integrate 175 Gigawatts of Renewable Energy into India's Electric Grid, Vol. I—National Study. Golden,* Colorado, US: NREL. Details available at https://www.nrel.gov/docs/fy17osti/68530.pdf

the sophistication required from power systems planning, operation, policy-making, and business strategy. Thus, a secondary objective of this work is to develop a sophisticated but transparent power system operation model, which can be used to support future decision-making and policy analysis and will be improved over time. The outputs of this model are freely available online at a dedicated website, which includes dynamic visualization and free download of the results.[4] TERI firmly believes that transparent, open-source analytical tools and datasets are crucial in helping to meet the growing challenge that the complexity of a high VRE power system poses to policy-makers, corporations, and civil society.[5]

This study is structured as follows. Section 2 discusses the scenario architecture that we have used and the logic that went into developing it. Section 3 describes the modelling approach and assumptions. Section 4 analyses the results of the different scenarios. Section 5 gives conclusions and policy recommendations, including an outlook for future areas of work.

4 https://teriin.org/etctool/

5 See also https://openmod-initiative.org/

02 SCENARIO ARCHITECTURE

2.1 Headline Scenarios

The scenarios analysed in this report have been designed across three different parameters, namely production capacities, transmission system, and power system flexibility.

***Production capacities*:** This refers to the assumptions regarding future capacities of different generation technologies, such as coal, gas, hydro, nuclear, wind, solar. For a mid-term study focusing on 2030, we have not used a cost-optimizing capacity expansion model. Rather, our capacity assumptions are defined exogenously from the power system operations model, based on recent studies by the CEA and others.[6] We develop two contrasting scenarios. The Baseline Capacities Scenario (BCS) assumes a mix of coal and renewables by 2030, and reflects broadly the assumptions of the 2018 National Electricity Plan, developed by the CEA.[7] The High Renewable Energy Scenario (HRES) has a higher level of renewable energy production capacity by 2030, approaching 450 GW and reflecting the assumptions of the CEA's Optimal Mix study.[8]

Transmission system: The transmission system is a crucial tool for the integration of high shares of VRE, allowing power to be transmitted around the country from locations of excess VRE supply to locations of high demand. We develop two contrasting transmission scenarios. In the Unconstrained Transmission Scenario, we assume that the power transfer capacities of each line have been expanded sufficiently by 2030 such that power can flow around the country in an unconstrained manner. A corollary – but implicit – assumption here is that the electricity market 'infrastructure' is likewise developed by 2030 to allow seamless interstate scheduling and dispatch of power. In the Expanded Transmission Scenario, we assume that the transmission system has been expanded by 2030 in line with existing plans, such as the National Electricity Plan, but such that there will still be some capacity constraints in power transfer. This scenario reflects a more fragmented electricity market, where power transfer is constrained by some infrastructural bottlenecks.

Power system flexibility: This refers to the capacity of the power system to flexibly integrate VRE, through supply-side, demand-side, and storage flexibilities (transmission flexibility is dealt with previously). In particular, we study two aspects. First, the impact of lower or higher technical minimums for coal-based power plants, i.e. the minimum level to which generation can be lowered before the plant must be switched off. This is a crucial parameter for the grid integration of VRE in India, as it allows the coal fleet to back down output when VRE is high (for example,

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[6] See footnote 2, and Pachouri, R., T. Spencer, and G. Renjith. 2018. *Exploring Electricity Supply-Mix Scenarios to 2030*. New Delhi: TERI. Details available at https://www.teriin.org/sites/default/files/2019-02/Exploring%20Electricity%20Supply-Mix%20Scenarios%20to%202030.pdf

[7] See CEA. 2018. *National Electricity Plan - (Volume 1) Generation*. New Delhi: Central Electricity Authority, Ministry of Power, Government of India. Details available at http://www.cea.nic.in/reports/committee/nep/nep_jan_2018.pdf

[8] See footnote 2.

at midday for solar) and ramp it up quickly when VRE output falls (for example, in the evening). Second, we explore the impact of integrating battery storage in the power system by 2030.

Table 1 gives an overview of the scenario combinations that we explore in this report by varying the assumptions across the parameters of production capacities, transmission, and system flexibility. The specifics of each sub-scenario across these three parameters are further discussed in the following section in which we describe the model set-up and assumptions. In developing these scenarios, we have tried to both isolate the impact of different assumptions and see their individual effects, and also combine them in order to analyse the combined effects.

Table 1: Scenarios Used in This Study

No.	Abbreviation	Capacities	Transmission	Flexibility
1	BCS_Baseline_Flex	Baseline Capacity Scenario	Expanded Transmission Scenario	Baseline Flexibility Scenario
2	BCS_Low_Flex	Baseline Capacity Scenario	Expanded Transmission Scenario	Low Thermal Flexibility Scenario
3	BCS_Trans_Flex	Baseline Capacity Scenario	Unconstrained Transmission Scenario	Baseline Flexibility Scenario
4	HRES_Baseline_Flex	High Renewable Energy Scenario	Expanded Transmission Scenario	Baseline Flexibility Scenario
5	HRES_Storage_Flex	High Renewable Energy Scenario	Expanded Transmission Scenario	Storage Flexibility Scenario
6	HRES_Thermal_Flex	High Renewable Energy Scenario	Expanded Transmission Scenario	High Thermal Flexibility Scenario
7	HRES_Trans_Flex	High Renewable Energy Scenario	Unconstrained Transmission Scenario	Baseline Flexibility Scenario

Source: *authors*

2.2 Scenario Sensitivities

In addition to the aforementioned headline scenarios, we also explore four scenario sensitivities in order to tease out the impact of alternative assumptions. These sensitivities are as follows:

1. ***Baseline_Cap_Baseline_Flex_High_Demand:*** In this scenario, we take the BCS, Baseline Flexibility scenario as the basis, but conduct a sensitivity analysis on the demand level, assuming a higher energy requirement and peak demand. We describe the assumptions in this regard in Section 3.2.1, where we describe the load assumptions for all scenarios.

2. ***Baseline_Cap_Baseline_Flex_15_Minute*****:** In this scenario, we reduce the temporal resolution of the model from an hour to 15 minutes. This allows us to analyse in greater detail the potential ramping constraints of meeting the net load,[9] which may be obscured with

[9] Net load is defined as load minus must-run VRE.

an hourly resolution. The baseline model is already extremely computationally intensive, requiring 10–12 hours with a world-class commercial solver to converge for a one-year hourly simulation. Increasing the temporal resolution to 15 minutes increases complexity in a non-linear fashion. For this reason, we conduct this sensitivity only for a one-week period. However, we have chosen for this purpose the week with the highest net load ramp in the hourly simulation, allowing us to be certain that the sensitivity explores the most challenging ramping period.

3. ***Baseline_Cap_Baseline_Flex_Low_Gas*:** In this sensitivity we assume lower imported gas prices and explore their impacts on power system operation. The detailed assumptions here are described in Section 4.6.3.

4. ***Baseline_Cap_Baseline_Flex_Fragmented_Markets*:** For this sensitivity, we assume that the present situation of largely self-scheduling and dispatch at the level of state electricity distribution companies (DISCOMs) still prevails, and simulate this by proxy through a hurdle rate on cross-border transfers of power. This proxies a situation in which the Central Electricity Regulatory Commission's (CERC) proposal to move towards Market-Based Economic Dispatch of power in a common pool has not been fully implemented, and DISCOMS continue to largely self-schedule without taking further advantage of opportunities for interstate arbitrage and resource sharing.[10]

Further details of these sensitivities are given in the ensuing sections.

[10] For the CERC proposal for moving towards Market-Based Economic Dispatch across the country, see CERC. 2018. Discussion Paper on Market-Based Economic Dispatch of Electricity: Re-designing of Day-ahead Market (DAM) in India. Details available at http://www.cercind.gov.in/2018/draft_reg/DP31.pdf

03 MODELLING DESCRIPTION AND ASSUMPTIONS

3.1 An Overview of the PyPSA Model and Its Implementation for India (PyPSA-India)

Python for Power System Analysis (PyPSA) is maintained by the Energy Systems Modelling group at the Karlsruhe Institute for Technology. PyPSA can model the operation of and investment in the power system, respecting both unit commitment and economic dispatch. The objective of PyPSA is to minimize system costs across the simulation period, while respecting technical constraints. PyPSA is an open-source model, with the source code freely available for download and modification. Further details of PyPSA are available on the website and in related peer-reviewed publications.[11]

For the purpose of this study, we have customized the PyPSA model to represent the Indian power system (and, hence, named the model as PyPSA-India). We operate the model essentially as a unit commitment and dispatch model. In simple terms, this means we take data on the installed capacities, loads, transmission infrastructure, and technical aspects of the power system as exogenous inputs into the model. We simulate every hour of the fiscal year 2030–31 (April 2030 to March 2031). The model simulates the process of unit commitment and dispatch on an hourly basis for every hour of the target year. This allows us to represent the operation of the power system with a high degree of fidelity to the technical constraints on the real-world operation of the power system. Crucially for a high coal system like India, this allows us to accurately represent the constraints on a coal plant operation such as minimum up time, minimum down time, and technical minimum (these constraints are explained in greater detail in the following sections).

Nodes are the fundamental units to which all other model components attach. In PyPSA-India, we break up the country into 23 nodes, each of which represents an Indian state or Union Territory. The exception here is the states of the North Eastern Region (NER), which (in view of the relative size of the power system in the NER) we treat as a single node (i.e. assuming a perfect copperplate transmission system within this region). In order to reduce the complexity of the model somewhat, we also combine small Union Territories into the node of their adjacent state. Thus, Puducherry is combined with Tamil Nadu and so on.

Loads, generators, storage units, and transmission lines attach to a single node and determine the power balance at the node. Loads represent a fixed power demand; a generator's dispatch can be optimized within its power availability; storage units can shift power from one time to another with conversion losses and power limits for charging and discharging. PyPSA-India simulates both unit commitment and dispatch and incorporates constraints such as transmission, scheduling, and the technical parameters of generating plants. The model commits and dispatches generating

[11] Brown, T., J. Hörsch, and D. Schlachtberger. 2018. PyPSA: Python for power system analysis. *Journal of Open Research Software* 6(1), arXiv:1707.09913, DOI: 10.5334/jors.188. See the PyPSA website https://pypsa.org/#sec-9 and dedicated publications page https://pypsa.org/publications/index.html

units on an hourly basis, with a 24-hour look-ahead for forecasts of load. Table 2 represents the components of the PyPSA-India model.

Table 2: Basic Components of PyPSA-India Model

Component Name	Component Description
Network	Container for all other network components
Node	Fundamental units to which all other components attach
Carrier	Energy carrier (e.g. wind, solar, gas)
Load	A consumer of energy
Generator	Generator whose feed-in can be flexible subject to minimum loading or minimum down and up times (e.g. a dispatchable unit), or variable according to a given time series of power availability (e.g. a variable renewable energy unit)
Storage Unit	A device which can shift energy from one time to another, subject to efficiency losses
Line	A transmission line connecting two nodes, allowing for the transfer of power between two nodes subject to line transfer capacities and impedance/reactance

Source: *authors*

3.1.1 Adaptations for India: Forced Outages

The base version of the PyPSA model does not have a modality for simulating the probabilistic representation of forced outages of dispatchable generators due to technical faults or other reasons. It is important in India to accurately represent forced outages, given the country's large thermal fleet and ongoing challenges, while maintaining the generating unit availability due to frequent technical faults. For this reason, in PyPSA-India, we implemented adjustments to the source code of the PyPSA model in order to conduct a probabilistic simulation of forced outages. For each timestamp, the model calculates the probability of a given generator being on outage and the probabilistic duration of the outage. Once a unit is on outage, it is maintained as such, until the previously determined duration of the outage ends, and the unit returns to the pool of generators available to be dispatched by the model. The probabilities of unit outage as well as outage duration were established based on examination of data on the historical operation of the Indian power system from CEA as well as consultation with sector experts.

Figure 27 in the Annex provides the conceptual framework for the simulation of forced outages. Figure 1 shows the share of the coal fleet on forced outage for each hour of the year, as a percentage of the whole coal fleet. At any given time, the share of the coal fleet on outage typically varies between 4% and 5%, with a peak outage rate of 7%. It is important to note that the modelling of generator outages is stochastic within the given probability of unit outage and outage duration. This means that each simulation cannot be perfectly compared with any other simulation, because each simulation will implement a slightly different schedule of forced outages. Notably, forced outages drive part of the unserved load in each scenario, and thus unserved load may vary in ways that are not necessarily driven by the fundamentals of each scenario.

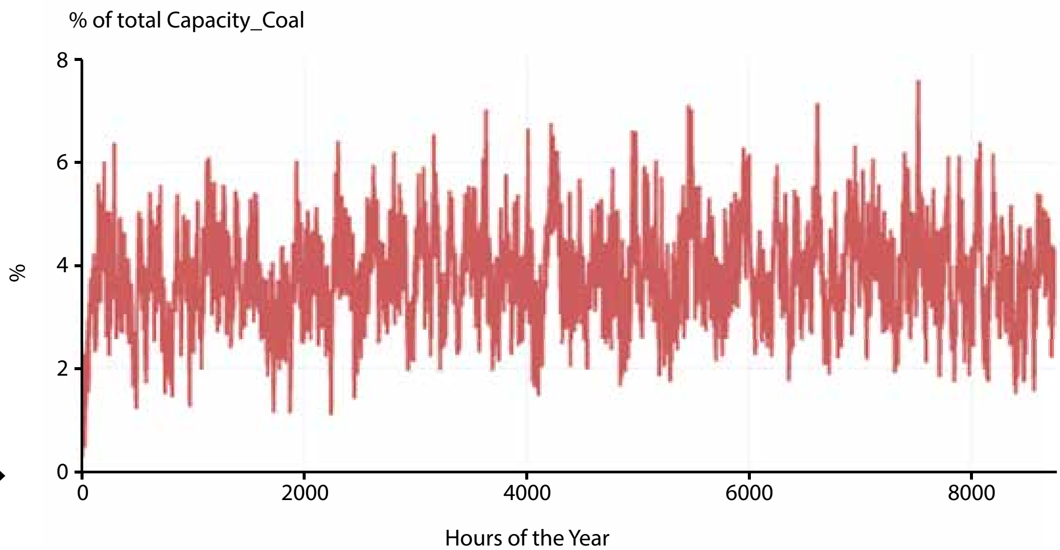

Figure 1: Total Share of the Coal Generating Fleet on Outage for Each Hour in the Year

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3.1.2 Adaptations for India: Gas and Hydro

The operation of natural gas and hydro-based power plants required specific treatment in PyPSA-India to represent Indian conditions as realistically as possible. The hydro fleet has been categorized into two groups, according to the degree of dispatchability (dispatchable reservoir and pondage hydro) and non-dispatchable run-of-river (RoR) hydro. For dispatchable hydro, we examined the historical unit-wise-generation data in order to come up with the unit-wise daily energy constraints. These energy constraints typically reflect the seasonal variation in generation pattern defined by monsoon, and policy to maintain minimum downstream flow rate, notably for agricultural and ecological purposes. Within the daily and seasonal energy constraint for dispatchable hydro, the model is given full flexibility to dispatch the daily and seasonal energy available in order to minimize the system-wide production costs. This typically means that dispatchable hydro is reserved for hours of peak demand, particularly during morning and evening, although the output of dispatchable hydro is both higher and more constant throughout the day during the monsoon months. By contrast, for RoR hydro stations, we used the historical daily generation pattern in order to define the resource profile. We further assumed must-run status for RoR hydro, based on its zero marginal cost.

In the case of natural gas plants, due to the large variation in gas prices, we categorized the fleet into two groups, namely those powered by cheaper domestic gas and those powered by more expensive imported gas. Due to limitations in the availability of domestic gas and assuming that there will not be more domestic gas allocation to the power sector, we have imposed a unit-wise monthly energy constraint, based on historical-generation data for domestic gas power plants. Within this monthly energy constraint, the model is free to dispatch the gas-fired unit in order to minimize the system-wide production cost. However, for imported gas plants, assuming that gas availability is not limited, we let the model dispatch imported gas plants freely according to their marginal cost, without any energy constraint. Practically, as shall be seen, there is very little dispatch of imported gas plants due to their high marginal cost.

3.2 Load Forecasts and Capacity Scenarios

3.2.1 Load Forecasts

As mentioned in Section 3.1, in PyPSA-India, the power system has 23 nodes, each one representing a State or Union Territory of India (with the exception, as mentioned, of small Union Territories which we clump into their corresponding state and the states of the NER, which we treat as a single node). For the sake of simplicity, we shall call these nodes 'states' hence forward. We make hourly load profile forecasts for 2030 for each of these states. First, we took at the state-wise historical data of hourly load profile for the period 2008-9 to 2017-18. Second, we assumed a continuation of historical growth rates and load profile shapes in order to derive the 2030 load profile and aggregate load for each state. Within this overarching framework, we made a couple of small adjustments:

- We lowered the growth rate for richer states by roughly 0.5 percentage points.
- We raised the growth rate for poorer states by roughly 0.5 percentage points.
- For a few states, we assumed some small *ad hoc* adjustments. For example, for Punjab, we did not assume load growth at the rate of the past, because of the importance of agricultural load in the state and the likelihood that this would saturate in the coming years.
- We assumed a reduction in Transmission and Distribution (T&D) losses to about 15% for each state by 2030 and used this rate of T&D losses to derive our generation requirement.
- We adjust upwards the 'peakiness' of each state load to reflect the decline in the load factor,[12] as per the 19th Electric Power Survey (EPS).

In aggregate, this approach gives us results that are comparable but slightly lower than those of the 19th EPS.[13] For the all-India level, our total energy requirement is 2260 TWh and the peak load is 304 GW for the year 2030–31. This compares with an energy requirement of 2530 TWh and a peak demand of 370 GW in the 19th EPS for the year 2031–32 (interpolating linearly, this implies 2434 TWh and 356 GW for 2030–31). Given the history of the EPS in consistently over-forecasting load growth[14] and recent softer GDP and load growth, we feel that a slightly lower load growth scenario is reasonable. It should be noted that these load projections were made before the impact of the COVID-19 pandemic on the Indian economy, and thus reflect our perception of the evolution of the Indian economy and electricity demand prior to the pandemic. The long-term impact of the pandemic on the world and Indian economies is highly uncertain as of the time of writing and should be the subject of future study of capacity, load, and system operation scenarios for the Indian power sector.

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[12] In this context, load factor is defined as the ratio of peak to average load. A lower load factor indicates a more 'peaky' demand profile, and vice versa.

[13] CEA. 2017. *Report on 19th Electric Power Survey of India*. New Delhi: Central Electricity Authority, Ministry of Power, Government of India.

[14] See, for example Prayas. 2017. *Many Sparks but Little Light: The Rhetoric and Practice of Electricity Sector Reforms in India*. Pune: Prayas Energy Group, in particular Table 5.3.

In addition, we also conducted a sensitivity on load growth, by assuming in the BCS High Demand Scenario that load is 10% higher than in the baseline forecast, and that this is allocated to each state in proportion to their share in the total load. For each state, we allocated this additional load equally to each of the hours of the year. In this scenario, the total energy requirement is 2491 TWh and peak demand is 336 GW, still slightly below but very close to the 19th EPS projections.

Table 10 in the Annex presents the state-wise energy requirement and peak load in the baseline scenarios. The full state-wise load profile forecasts are available for download from the PyPSA-India website.

3.2.2 Aggregate Capacity Scenarios

As mentioned previously, we do not endogenously model the development of the capacity mix out to 2030 using a capacity expansion model, with an objective to minimize the total system costs, including investment costs. Rather, we exogenously take a certain capacity mix for 2030, based on the capacity expansion scenarios developed by others, notably the CEA. This is partly a result of the design of the PyPSA-India model as we have used it, namely as a power system operation model, and not as a capacity expansion model. The base version of the model, PyPSA, does have a capability to operate in capacity expansion mode, but this requires relaxing constraints of unit commitment and economic dispatch. As we are interested in modelling the power system operation in as much detail as possible, for this study we used PyPSA-India solely as an operational model and did not use the capacity expansion functions of the base model. We would also expect that 2030 is close enough in time that a reasonable understanding of the capacity mix could be developed without a cost-optimizing capacity expansion model.

Table 3 presents the technology-wise gross capacities and net generation in the BCS and HRES, and compares them to the most recent data from FY 2019–20.[15] Total VRE capacities of wind and solar are 318 GW and 399 GW in the two scenarios respectively, while the share of zero carbon generation capacities are 61% and 65%, respectively. The total share of zero carbon capacities is 62% and 66% respectively, substantially above India's Nationally Determined Contribution (NDC) target of 40% (the current level as of February 2020 is 37.2%). Thus both the BCS and HRES assume extremely rapid growth in VRE capacities.

Assumptions for the thermal fleet are the same across the two scenarios. This reflects that, firstly, investment decisions shaping the thermal fleet in 2030 have largely already been made; and secondly, that, as we shall see later in the report, the thermal fleet is an important resource for balancing VRE. Within the thermal generation fleet, the increase from 230 GW to 263 GW comes from coal, with the total coal capacity growing from today's level of 205 GW to 238 GW by 2030 in both the scenarios. The gas and liquid fuel capacities are assumed to stay the same as of today, at 25 GW and 0.5 GW, respectively. Further details regarding source-wise generation are given in the subsequent sections; the presentation here is intended only to give the reader a readily accessible overview of the scenarios.

[15] The Indian fiscal year runs from April 1st to March 31st

Table 3: Capacity Scenarios Used in This Study (GW)

	FY 2019-20		2030 BCS		2030 HRES	
	Installed Capacity (GW)	Gross Generation (TWh)	Installed Capacity (GW)	"Ex bus Generation (TWh) "	Installed Capacity (GW)	"Ex bus Generation (TWh) "
Thermal	231	1044	263	1319	263	1187
Nuclear	7	46	17	91	17	91
Large Hydro	46	156	74	231	74	226
Wind	38	65	129	292	169	378
Solar	35	50	189	286	229	337
Biomass and waste	10	14	23	27	23	28
Small Hydro	5	9	10	14	10	14
Total	**370**	**1385**	**705**	**2260**	**785**	**2260**

Note:

1. Thermal refers to coal, lignite, imported and domestic gas, and liquid fuel plants. Large hydro refers to dispatchable pondage and reservoir hydro and RoR hydro above 25 MW. Wind refers to only onshore wind. BCS and HRES generation is not equal due to rounding.
2. Ex-bus generation is net of auxilliary power consumption (6%, 3%, 1%, 12% and 8% for coal, gas, hydro, nuclear and biomass respectively) of various power plants..

3.3 Generator Constraints and Marginal Costs

As a power system operation model, PyPSA-India imposes a number of constraints on generators, in order to reflect their real-world operational characteristics. These include parameters such as technical minimum, minimum up time and down time, ramp rates, and start-up costs. We have taken assumptions on these technical parameters based on a review of the literature,[16] observations of real-world operations of Indian power plants, and discussions with sector experts.

Table 4 displays the technology-wise constraints that we impose in the model. It should be noted that as PyPSA-India runs with hourly timestamps, certain constraints are denominated per hour. Thus, our coal ramp rate is 60% of nominal power per hour, which equates to a – rather conservative – assumption of 1% of nameplate capacity per minute.[17]

It should be noted that the constraints in Table 4 are those of the Baseline Flexibility Scenario. In the Low Thermal Flexibility Scenario (see Scenario_2 in Table 1), we assume that state-owned[18] coal-fired power plants have a higher technical minimum of 65%, compared to the baseline assumption of 55%. Currently, the CERC has issued a regulatory order, mandating a 55% technical minimum for plants under its jurisdiction (Central Generating Stations and Inter-State Generating Stations), but state-owned plants do not come under this order and currently operate at much

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[16] In particular, NREL's 'Greening the Grid' study.

[17] See for example, AgoraEnergiewende. 2017. Flexibility in Thermal Power Plants: With a Focus on Existing Plants. Details available at https://www.agora-energiewende.de/fileadmin2/Projekte/2017/Flexibility_in_thermal_plants/115_flexibility-report-WEB.pdf

[18] That is, those owned by the governments of the states of India, as opposed to the central government (federal government in international parlance).

higher technical minimums (65–70%). By contrast, in the High Thermal Flexibility Scenario (Scenario_6 in Table 1), we assume that centrally owned and Inter-State Generating Stations owned by Independent Power Producers (IPPs) can achieve a 40% technical minimum by 2030.

Table 4: Generator Constraints

Constraint	Units	Coal	Gas	Biomass and Waste	Hydro
Technical Minimum	% Nominal Power	55%	40%	30%	10%
Ramp Rate Up	% Nominal Power/Hr	60%	100%	100%	100%
Ramp Rate Down	% Nominal Power/Hr	60%	100%	100%	100%
Minimum Up Time	Hrs	4	3	3	0
Minimum Down Time	Hrs	6	3	3	0
Start-up Costs	INR/MW	14100	6690	14100	0

The assumptions are those of the Baseline Flexibility Scenario.

We turn now to assumptions on marginal costs. PyPSA-India contains an individual representation of each generating unit, with 529 coal units and 80 gas-generating units. We compute unit-wise marginal costs for gas and coal, based on marginal cost data from public sources,[19] and where these are not available or are out of date, we infer the marginal cost for certain units based on the technology characteristics and distance from coal sources. It should be noted that we assume a 4% escalation rate for fuel prices between the base year and 2030, which approximates to the nominal coal price inflation rate over the last several years; the real escalation rate was about 1% per year.[20] Real cost escalation would depend on the inflation rate assumed between the base year and 2030: the important point for the operation of the model is like treatment of relative costs (i.e. between fuels); here we ensure that all prices in 2030 are nominal. A second important point is the simplification that we make regarding a constant marginal cost irrespective of unit loading and unit heat-rate. This dramatically simplifies the model.

The Figure 2 represents the unit-wise marginal cost assumed in the model. The wide variation between coal-based marginal costs reflects the wide dispersion of coal-based plants across India and the importance of transport costs in marginal costs, as well as the wide dispersion of technical efficiency between the older and newer generating units. The huge spread between domestic and imported gas marginal costs is reflective of the (artificially) low price of domestic gas, and the rigid oil indexed contracts that are used to price India's imported LNG. Given the possibility of substantial oversupply in global LNG markets and the addition of new import capacity in India, we also conduct a sensitivity analysis in order to study the impact of lower imported gas prices (see Section 4.6.3). In the mid-term to 2030, lower imported gas prices may impact system operation, but given the absence of new gas plants from any capacity expansion plans currently, lower gas prices seem unlikely to significantly impact installed capacities of gas-based plants to 2030.

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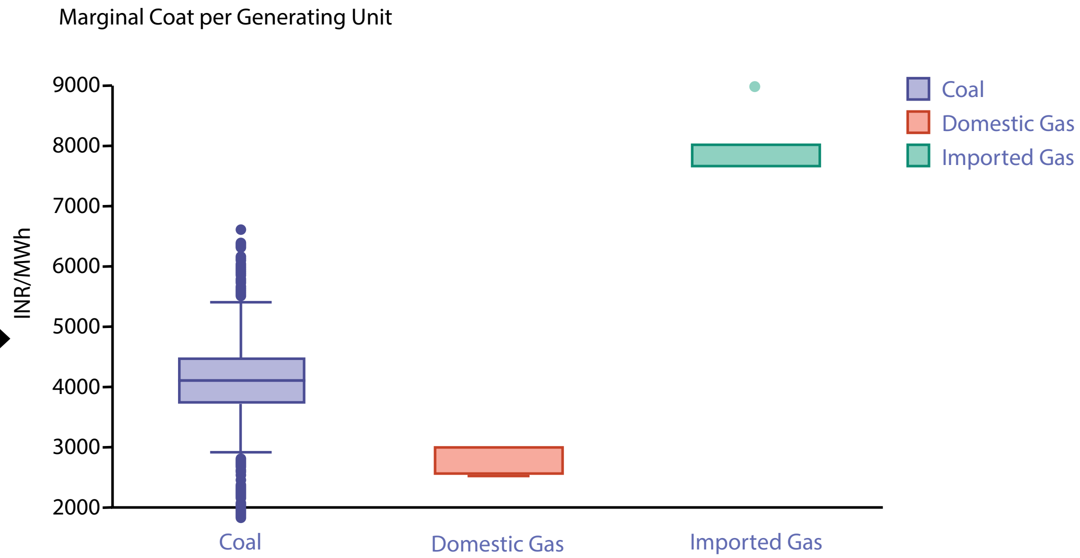
[19] Notably from http://meritindia.in/

[20] See Spencer, T., R. Pachouri, G. Renjith, and S. Vora. 2018. *Coal Transition in India*. New Delhi: The Energy and Resources Institute. Details available at https://www.teriin.org/sites/default/files/2018-12/Coal-Transition-in-India.pdf

Figure 2: Unit-Wise Marginal Costs for Coal, Domestic Gas, and Imported Gas



Note: the box at the top and bottom represent the first quartile (25th percentile) and third quartile (75th percentile), while the plot 'whiskers', where applicable, represent the maximum and minimum values, excluding statistical outliers. The individual dots represent statistical outliers.

3.4 Assumptions on Battery Storage

In the HRES, Storage Flexibility Scenario (Scenario 5 in Table 1), we assume the addition of some battery storage facilities in the model. The size, operational characteristics, and state-level location of these facilities were determined out of the model, by examining the results of state-level solar and wind curtailment in the HRES, Baseline Flexibility scenario. Here, we computed the state-wise curtailment duration curves. The slope of these curves was very steep, indicating that curtailment is largely a transitory phenomenon for at most one or two hours within a day on affected days. We then sized the battery facilities in order to ensure sufficient operating hours in the year and to make each battery unit a worthwhile investment. This resulted in some 60 GW of storage units in power terms, and about 120 GWh in energy terms. Given the steepness of the curtailment duration curves in the HRES, Baseline Flexibility scenario, a power to energy ratio of 2 was most effective at reducing curtailment while minimizing the investment in storage.

3.5 Transmission Scenario

In PyPSA-India, the transmission system is modelled as lines connecting one node to another and allowing power to flow according to impedance/reactance values, line transfer capacities, and transmission line length. For the 2030 study, we modelled interstate transmission lines, while ignoring the intrastate transmission lines within states. In other words, each state was treated as a single balancing area. In the model, power flows through lines according to the power imbalances at the nodes and the impedances in the network. Power flow amongst interstate lines is calculated using linearized DC optimal power flow (OPF). The data for power transfer capability and impedance were obtained from the Power System Operation Corporation of India (POSOCO) for the base year.

In order to analyse the need for transmission system expansion by 2030, we first undertook a simulation with no transmission constraints and examined power flow in this scenario relative to the transfer capacities in each line in the base year. In doing so, we looked both at peak unconstrained power transfer relative to base year line transfer capacities and the duration curves of power transfer for each line. Building new transmission infrastructure should take into account the utilization rate of the infrastructure, hence the interest in looking at the duration curve of power transfer. Based on this analysis, we added additional MW transfer capacities to some lines, where unconstrained power transfer exceeded base year line capacity for a substantial portion of the year 2030.

Table 5 shows the interstate and interregional transmission line capacities across various regions in our model. Scenario-wise, line-wise power flows are available for download from the PyPSA-India website.

Table 5: Aggregated Interstate and Inter-Regional Transfer Capacities in the BCS, Expanded Transmission Scenario (MW)

Region	ER	NER	NR	SR	WR
ER	63444	21435	0	8498	0
NR	44373	0	169853	0	34088
SR	0	0	0	51256	0
WR	45245	0	0	14255	45484

Source: authors

3.6 RE Production Profiles and Capacity Siting

Generation from VRE generators is a function of various factors, such as solar irradiance, tilt angle, location, and altitude in the case of solar; and hub height of the wind turbine and wind speed for each location in the case of wind. We allocated generation capacities to each state based on our GIS model of state-wise wind and solar resource potentials, which takes into account renewable resources, land-use patterns, and infrastructure development. In this regard, priority has been given to states having more VRE potential. To create hourly generation profile of RE, we used the System Advisory Model (SAM) of National Renewable Energy Laboratory (NREL) in the United States. This model produces solar and wind resource profiles for each hour of the year and each location in the model, based on input data of historical weather, VRE location, and generator characteristics. These state-specific resource profiles, multiplied by the state-specific VRE capacities, drive hourly VRE generation at each node in the model before curtailment, if required.

04 RESULTS

4.1 Aggregate Scenario Results

4.1.1 Key Indicators

In this section, we present an overview of the aggregate results of the scenarios studied in this report (see Table 6). Each scenario analysed here has the same energy requirement and peak load of 2260 TWh and 304 GW, respectively (the BCS, High Demand scenario is analysed separately in Section 4.6.1).

None of the scenarios has a significant problem with unserved load, which approaches, for all practical purposes, zero in all scenarios. This is an indication of the adequacy of dispatchable resources, relative to peak load. Net dispatchable capacities reach 332 GW relative to peak load of 304 GW.[21] Total VRE curtailment ranges between 0.2% in the HRES, Storage Flexibility scenario and 4.0% in HRES, Baseline Flexibility scenario. In the HRES, Baseline Flexibility scenario, the absence of additional flexibility options constrain the model to curtail excess VRE generation, particularly excess solar injection at midday but also excess wind in monsoon. On the other hand, the HRES, Transmission Flexibility scenario, with essentially unlimited power transfer capacities around the country, has a similar level of VRE curtailment as the HRES, Baseline Flexibility scenario. This indicates that in the HRES, curtailment is largely driven by the operational constraints of the coal fleet, rather than local inadequacies in transmission.

The aggregate gas plant load factor (PLF) is very low at around 17%, a few percentage points below the current level (19% in 2018). This is because of the high cost of imported natural gas relative to other fuels, and the adequacy of alternative dispatchable resources to meet peak load. The aggregate hydro PLF is relatively stable throughout all scenarios, reflective of its zero marginal cost and usefulness for balancing VRE when available. The coal PLF varies marginally between the different BCS, but drops substantially in the HRES. It is worth noting, however, that in the BCS the coal PLF is higher than the 56% seen in FY2019–20. In the BCS, the growth of the coal PLF compared to today's level reflects the fact that both energy requirement and peak load grow faster than coal capacities.

[21] This excludes the BESS available in the HRES, Storage Flexibility scenario

Table 6: Aggregate Scenario Results: Key Indicators

Scenario Name	Unserved Load	Solar Curtailment	Wind Curtailment	Gas PLF	Hydro PLF	Coal PLF
	MWh	%	%	%	%	%
BCS_Baseline_Flex	0.00	0.41%	0.27%	16.75%	36.15%	65.48%
BCS_Low_Flex	2.00	0.53%	0.34%	16.70%	36.04%	65.55%
BCS_Trans_Flex	38.74	0.34%	0.01%	16.66%	36.03%	65.55%
HRES_Baseline_Flex	39.19	2.73%	1.29%	16.47%	35.32%	58.77%
HRES_Storage_Flex	0.00	0.10%	0.08%	16.55%	36.05%	57.77%
HRES_Thermal_Flex	21.16	1.16%	0.73%	16.62%	35.68%	58.34%
HRES_Trans_Flex	214.00	3.00%	0.92%	16.41%	35.06%	58.92%

Source: authors

4.1.2 Emissions

Having looked at these summary indicators, we now turn to fuel-wise generation shares and emissions. Table 7 shows the generation shares for key technologies, as well as indicators for CO_2 emissions and intensity. In all scenarios, the coal share of total generation drops substantially, from 73.1% in 2018 to about 57% in the BCS. This represents a rapid decline, but is consistent with what other countries have achieved, with China, for example, achieving a 12-percentage point reduction in the share of coal in generation between 2011 and 2018. Total VRE ranges between 26% in the BCS and 32% in the HRES. This is split roughly evenly between solar and wind, with the share of solar reaching a maximum of 15.3% of generation. This would imply that India reaches levels of solar penetration that no major economy has achieved as of today (California achieved 11.4% solar in 2018, and will certainly exceed 15% by 2030). This represents a substantial challenge for India, given the large daily swings in solar output.

Total zero carbon generation reaches a maximum of 48.5% in the HRES, Storage Flexibility scenario. It is one percentage point higher in this scenario compared to the HRES, Thermal Flexibility scenario because of the lower level of curtailment. Total generation from thermal grows by between 13% in the HRES and 26% in the BCS from today's level of 1045 TWh in FY 2019–20. All of this growth in thermal comes from coal, with gas and liquid fuel generation broadly the same as it is today.

However, emissions growth is more moderate. The emissions factor of fossil-fuel fired plants is assumed to improve, due to the retirement of older, less efficient plants. CO_2 emissions from the power sector increased between 3% and 17%, with almost negligible increase in the HRES, due to the huge growth of VRE as well as the improvement in fossil emissions factors and the compression of gas and diesel generation. It should be noted that these numbers are indicative, as they are calculated exogenously from the model and do not take into account the degradation in station heat rate due to lower PLF and more frequent cycling of output above technical minimum, and starts and stops. The grid emissions factor declines in all scenarios, by between 30% and 38% from today's level of about 710 gCO_2/kWh.

Table 7: Generation Shares and CO_2 Emissions Indicators

Scenario Name	Coal	VRE	Zero Carbon	Total Power Sector Emissions	Grid Emissions Factor
	%	%	%	$MtCO_2$	gCO_2/kWh
BCS_Baseline_Flex	57%	26%	42%	1134.59	502.04
BCS_Low_Flex	57%	26%	42%	1135.20	502.31
BCS_Trans_Flex	57%	26%	42%	1135.69	502.52
HRES_Baseline_Flex	51%	32%	47%	1019.88	451.28
HRES_Storage_Flex	50%	32%	48%	1002.76	442.83
HRES_Thermal_Flex	51%	32%	48%	1012.10	447.84
HRES_Trans_Flex	51%	32%	47%	1021.79	452.13

Source: authors

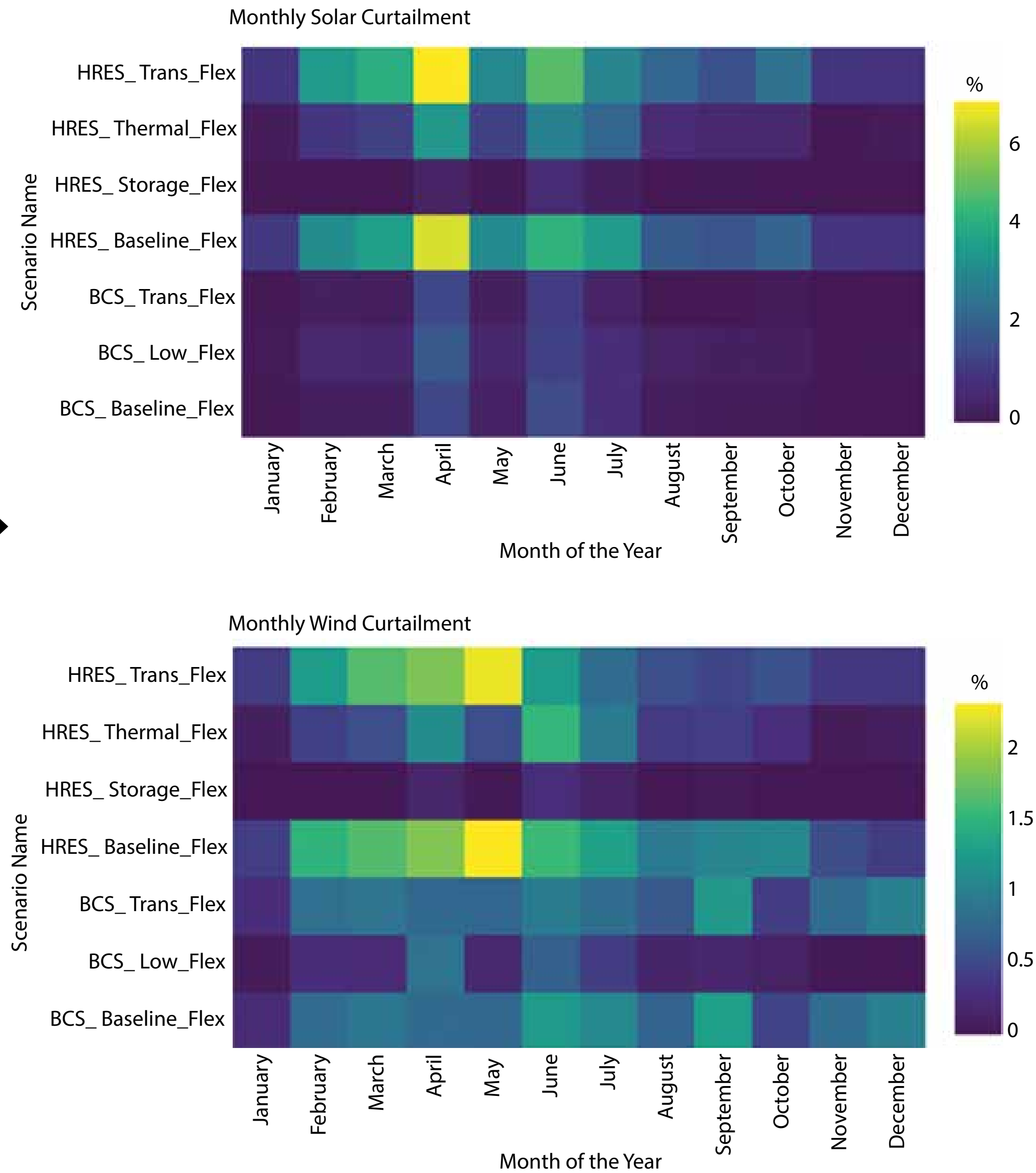
4.1.3 Curtailment

Figure 3 shows wind and solar curtailment by scenario and month of the year. As noted in Table 6, the aggregate level of wind and solar curtailment is relatively low across all the scenarios, with a minimum of 0.18% in the HRES, Storage Flexibility scenario and a maximum of 4.02% in the HRES, Baseline Flexibility scenario.

Solar curtailment is most intense in the months of March, April, May, and June. In April, in particular, the evening peak load is high, while hydro and wind generation has not yet picked up with the arrival of monsoon. This means that coal must provide the vast majority of the daily ramping. Given that coal plants cannot be shut off at midday and turned on in order to support the evening peak, solar must be curtailed in order to leave online sufficient coal capacity at midday to meet the evening ramping. This explains why peak solar curtailment occurs in April, and to a lesser degree during monsoon. The presence of substantial amounts of curtailment in the HRES, Unconstrained Transmission scenario (3.92% in aggregate) indicates that curtailment occurs because of a ramping constraint and not a localized transmission constraint. This conclusion is further supported by the fact that the aggregate wind and solar curtailment drops to 1.89% in the HRES, High Thermal Flexibility scenario. In this scenario, the lower technical minimum of centrally owned plants allows for a lower turndown of the coal fleet at midday and, hence, greater absorption of solar without curtailment.

Unlike solar, the peak monthly wind curtailment is lower, with a maximum value of 2.5% occurring in the month of July in the HRES, Baseline Flexibility scenario. In addition, wind curtailment concentrates in the monsoon months, when wind output is highest. Hydro output is also highest in monsoon, forcing the coal fleet to back down. The model is thus forced to curtail wind output at certain times in order to ensure that sufficient coal capacities remain online in order to meet variations in net load. Curtailment is lowest in the High Renewables, Storage Flexibility scenarios, even lower than in the Baseline Capacity scenarios. The role of storage is analysed further in Section 4.3.

Figure 3: Heatmap of Wind and Solar Curtailment by Scenario and Month of the Year



Source: authors

4.1.4 Costs

In this section, we analyse the scenario outputs in terms of costs, broken down into fixed and variable costs. Fixed costs refer to the annuitized capital cost and fixed operating cost of all the generators and storage units in the model, for the given year. Variable costs refer to the fuel costs, start-up costs, and variable operating costs. This excludes the heat rate penalty for partial loading of coal plants, which as discussed in Section 3.1 is not included in order to keep the model solution tractable. We present system costs on a per unit basis by dividing the sum of fixed and variable costs for the year 2030 by the total electricity generation in that year.

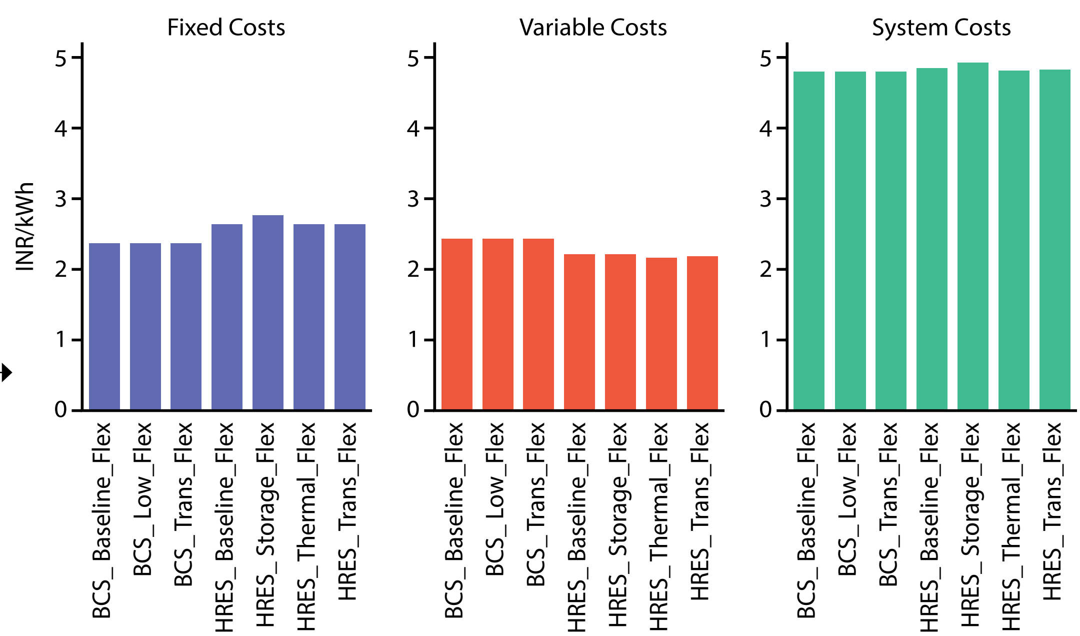
Figure 4 shows, per unit fixed, variable, and total costs. These are presented on a common y-axis, even though this inhibits the visualization of the differences between the scenarios. This is indeed the key point to stress: at the level of total system costs, the difference between the scenarios is so small as to fall well within the margin of error of these calculations. Thus, the HRES can be as cost-effective as the BCS at the level of the total costs of the system.

As expected, the per unit costs of the HRES are higher than those of the BCS. This is because total installed capacities are substantially higher in the HRES as compared to the BCS. In the BCS, installed capacities are the same, and thus the system-wide fixed cost is the same at 2.37 INR/kWh. In the HRES, Baseline Flexibility scenario system-wide fixed costs increase to 2.63 INR/kWh. Fixed costs are highest in the HRES, Storage Flexibility scenario at 2.77 INR/kWh, driven by the additional investment cost in battery storage facilities.

On the other hand, the HRES display lower per unit variable costs, because the addition of further zero marginal cost renewables pushes out higher marginal cost sources of generation. The effect is quite substantial. In the BCS, Baseline Flexibility scenario the per unit variable costs are highest at 2.43 INR/kWh. In the HRES, Baseline Flexibility scenario per unit variable costs fall to 2.2 INR/kWh. They are lowest in the HRES, Storage Flexibility scenario at 2.14 INR/kWh, as storage outcompetes high marginal cost sources of generation.

The net effect of these different trends is that total system costs are nearly identical between the two broad scenario capacities. The total system costs are 4.8 INR/kWh in the BCS, Baseline Flexibility scenario and 4.83 INR/kWh in the HRES, Baseline Flexibility scenario. The total system costs are highest in the HRES, Storage Flexibility scenario at 4.92 INR/kWh. The key point from this analysis is that the HRES is as cost-effective as the BCS renewables scenario because of this substitution between fixed and variable costs. The small difference between the scenarios is well within the margin of error of these calculations.

Figure 4: Per Unit Fixed Costs, Variable Costs, and Total System Costs



Source: authors

4.2 Operation of the Power System

In this section, we examine in more detail the operation of the power sector under the different scenarios described above. We analyse how different generation resources play a role in balancing VRE, and the role of different flexibility options in integrating VRE into the power system. We begin by providing a visual representation of the all-India power system dispatch under the BCS and HRES.

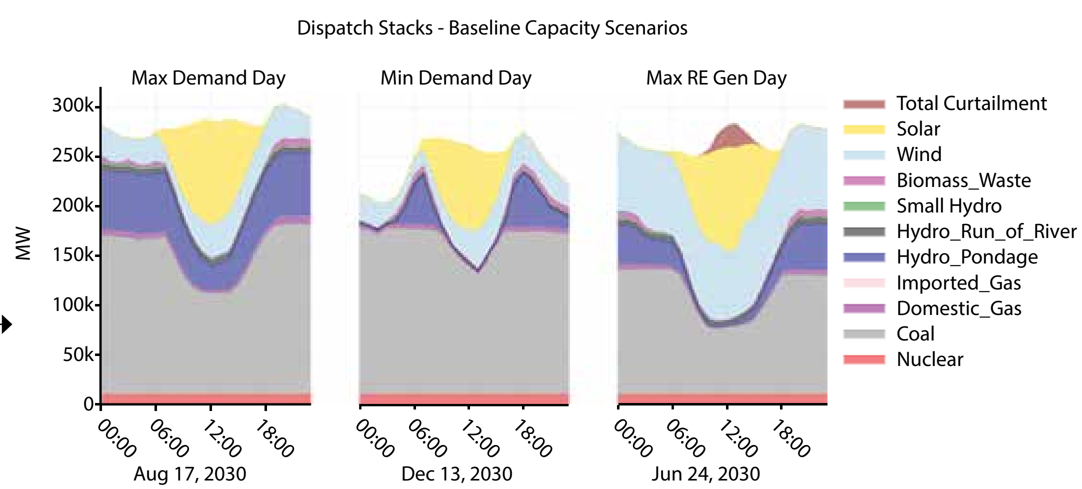
4.2.1 Aggregate All-India Dispatch Stacks

Baseline Capacity

Figure 5 shows the all-India dispatch of the power system under the BCS, Baseline Flexibilities scenario, for the maximum demand day, minimum demand day, and maximum VRE generation day. According to our load profile modelling, these days occur on August 17, December 13, and June 24, respectively. Figure 5 demonstrates that wind gives fairly good peak support during the maximum demand day, which coincides with the period of high wind output during monsoon (we look at the issue of the coincidence of wind and solar output with load in Section 4.6.1). It should be mentioned, however, that historical data on wind resource profiles is lacking in India, and a probabilistic approach to the capacity credit for wind during peak demand periods cannot be conducted based on historical data. Hydro also gives peak support as hydro output is strong during monsoon.

During the minimum demand day, coal generation is actually higher than during the maximum demand day. This is because the minimum demand day is also a day of low wind and hydro output, falling in winter. Thus, maximum ramping down of coal does not occur during minimum demand, but rather during maximum RE output (see Figure 5, right panel). On the maximum RE day, coal must be ramped down as far as possible, and still some curtailment occurs at midday. This is because coal cannot be ramped down any further without switching off, in which case insufficient capacity would be available to ramp up to meet the load in the evening.

Figure 5: All-India Dispatch Stacks in the Baseline Capacity, Baseline Flexibility Scenario

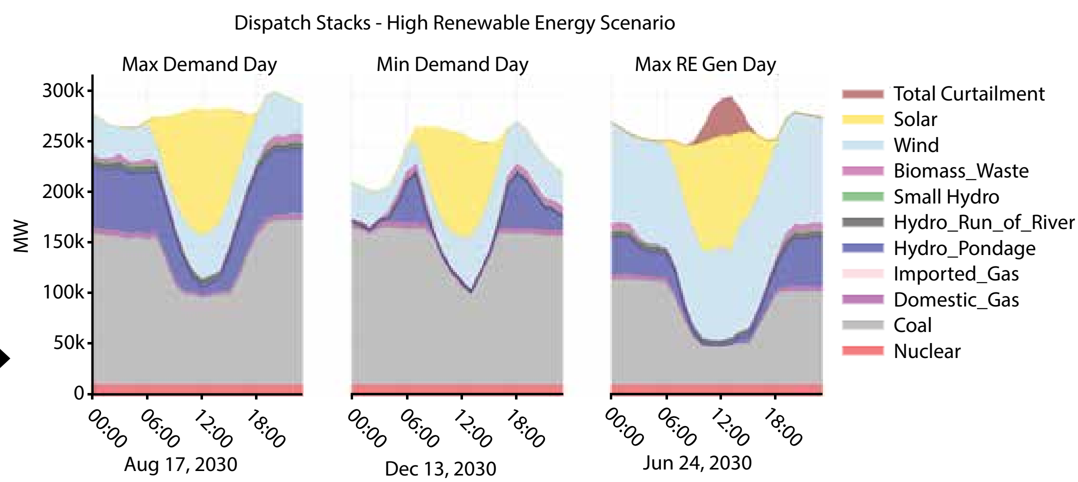


Source: authors

4.2.1.2 High Renewables

Figure 6 shows the same all-India dispatch stacks for the maximum and minimum demand days, and maximum RE generation day for the HRES, Baseline Flexibility scenario. As with the BCS, the peak demand day does not require maximum output from the coal fleet, because peak support is provided by hydro and to a lesser degree by wind. As noted above, a probabilistic estimate of the capacity credit for wind during times of peak demand would require historical data on wind output, which is not available as of today. In the HRES, the coal fleet is turned down to as low as 50 GW during the hours of maximum VRE injection at midday, but the substantial availability of hydro and wind provide peak support, allowing about 50% of the coal fleet to be switched off, with the remaining 50% providing load following services.

Figure 6: All-India Dispatch Stacks in the High Renewable Capacities, Baseline Flexibility Scenario



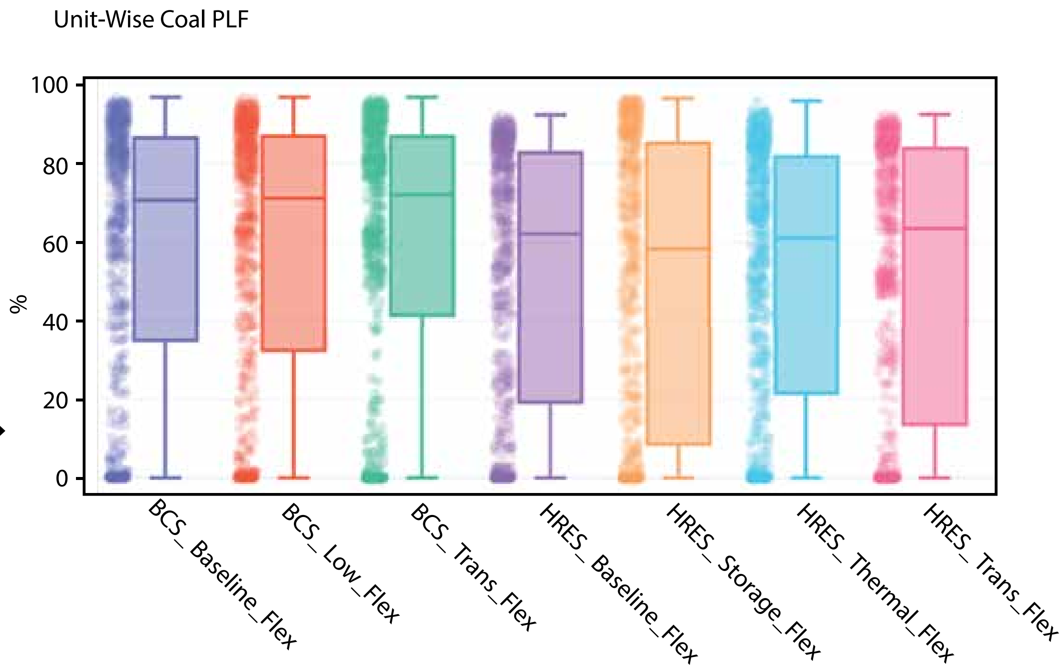
Source: authors

4.2.2 Coal Fleet Plant Load Factor

In all the scenarios, the coal fleet plays an important role in balancing VRE. In the BCS, the coal fleet PLF actually increases from today's levels, because the load grows faster than the addition of new coal-based generating resources. By contrast, in the HRES, the coal fleet PLF remains in the order of 57%–58%, compared to today's level of 56% in FY 2019–20 (and an average in recent years of about 60%). However, these aggregate numbers hide interesting differences within the fleet and between regions.

Figure 7 shows the unit-wise distribution of the coal fleet PLF in the seven headline scenarios that we analyse in this report. It is worth noting the very wide dispersion of PLF among the fleet within each scenario, with a number of plants operating at close to 85% annual PLF. These are notably mine-mouth plants with very low variable costs. At the other end of the extreme, there is a group of plants, which, regardless of the scenario, never start. This is because of their very high marginal cost, and the model's ability to draw power efficiently from around the country in order to meet the operating constraints at lowest cost. This shows that the key impact for the distribution of coal plant PLF depends not so much on the level of renewables in the scenario, but rather on the assumption of sufficient transmission infrastructure and efficient interstate scheduling and dispatch. Thus, the CERC's proposal to shift towards Market-Based Economic Dispatch in the day ahead market is likely to have a substantial impact on the distribution of coal plant PLF.

Figure 7: Unit-Wise Coal Fleet Plant Load Factor

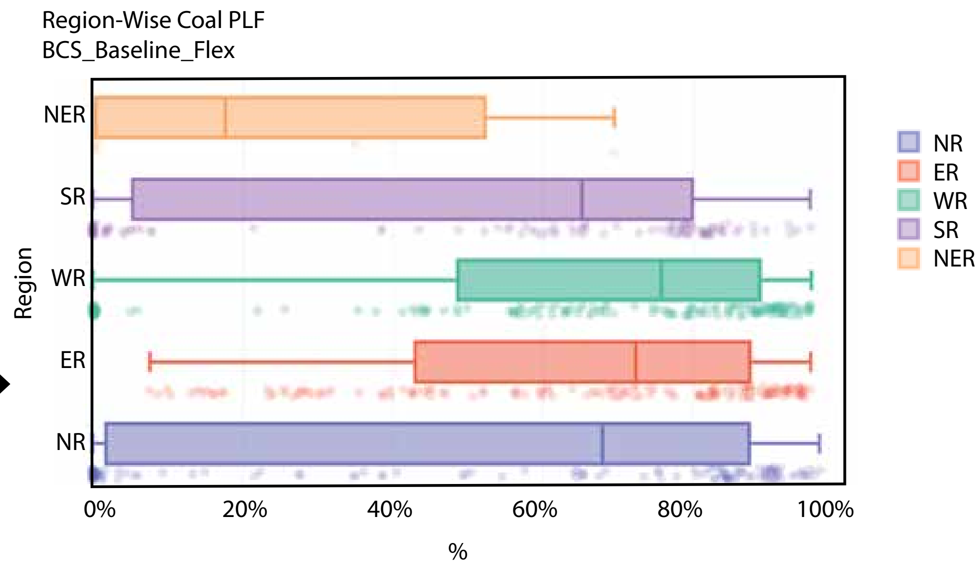


Source: authors

It is worth noting the impact of the different flexibility scenarios on the coal fleet PLF as well. Notably, the introduction of battery storage has a particular impact on the higher marginal cost plants. In the HRES, Storage Flexibility scenario, the median coal plant PLF is only four percentage points lower than the median coal plant PLF in the HRES, Baseline Flexibility scenario without storage. However, the bottom quartile of coal plant PLFs in the HRES, Storage Flexibility scenario is a full ten percentage points lower than in the HRES, Baseline Flexibility scenario. This indicates that there is substantial scope for battery storage to compete against the higher marginal cost coal plants forming the bottom quartile of coal plants.

There is also substantial difference between regions, as a result of the differences in coal plant marginal costs and the efficiencies brought about by transmission infrastructure and interstate scheduling and dispatch. Figure 8 shows the region-wise, unit-wise coal PLF in the BCS, Baseline Flexibility scenario. Both the Western and Eastern Regions, because of their proximity to coal resources and cheaper marginal costs, generally have high PLF, while the reverse is true for the Southern and Northern Regions. This implies, by definition, that the Northern and Southern region consumers would be the beneficiaries of a more integrated national power market, as they could procure cheaper power. On the other hand, producers in the Western and Eastern regions would also be the beneficiaries as they could sell power at a higher equilibrium price than in their home markets (the implication of this is that equilibrium prices for consumers would rise in these regions too, although all-India welfare would be improved. Consideration of the distributional impacts of power market integration is an important concern in moving towards a more integrated power market and something, incidentally, that PyPSA-India can help to explore in more detail).

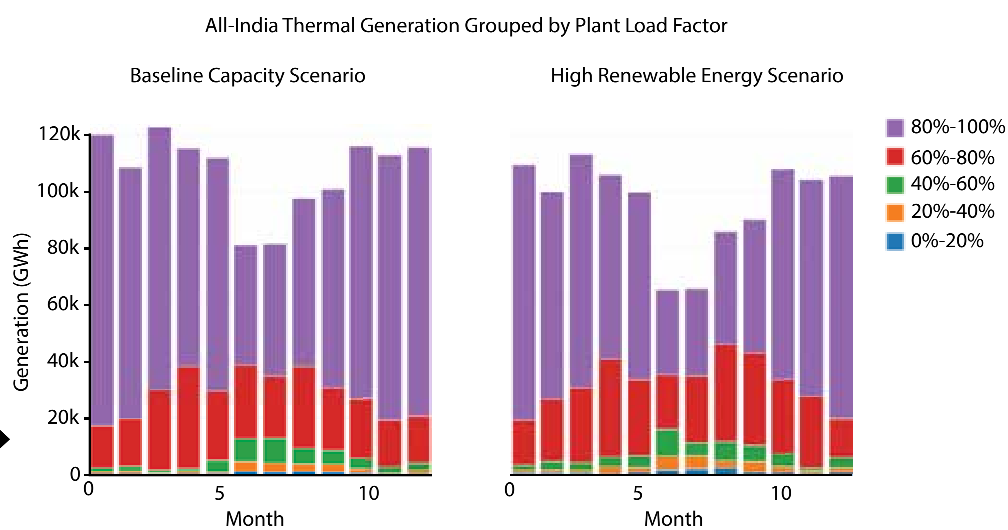
Figure 8: Region-Wise, Unit-Wise Coal PLF in the BCS, Baseline Flexibility Scenario



Source: authors

Figure 9 shows the all-India coal fleet output by month, for the BCS and HRES, Baseline Flexibility scenarios. We further classify the output according to the PLF of the plants concerned, grouping PLF into bins of 20 percentage points (see Figure 9). The coal plant output varies with the seasons, declining substantially during the months of June, July, August, as wind and hydro output increase with monsoon. On the other hand, it is interesting to note that between the BCS and the HRES, the most substantial drop in coal output across the year occurs among plants with a PLF of 80–100%. This may seem paradoxical, but there is a good reason for this. Notably, output from plants in lower PLF categories is determined not by their relative marginal costs as such, but rather by the need of the model to draw on them in order to integrate VRE. The output of these plants is still required to integrate VRE, and thus the decline in output falls more on the higher PLF category of coal units (see Section 4.2.4 for a further discussion on this issue).

Figure 9: All-India Coal Generation by Month and Plant Load Factor Grouping



Source: *authors*

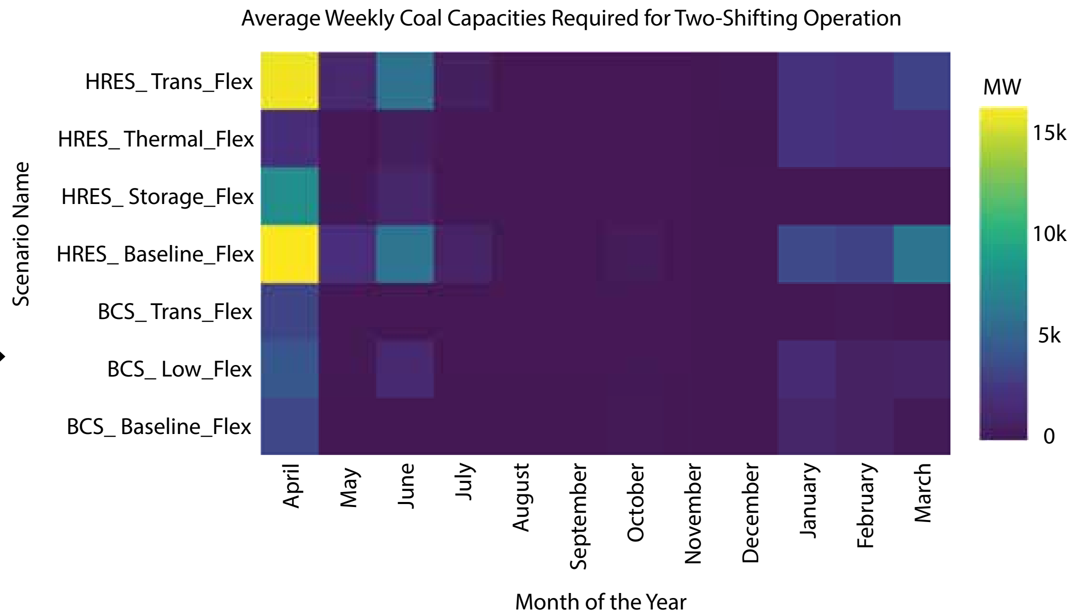
4.2.3 Two-Shift Operation of the Coal Fleet

Two-shifting refers to coal unit operation in which the unit is switched on and off again within a short period of time, and on a regular basis. This mode of operation can be necessary to integrate VRE, particularly solar with its strong daily swings of output. For the purpose of analysing the requirement for two-shifting, we define two-shifting operation as four or more unit starts within a week. Figure 10 displays a heatmap of the required capacities on two-shifting operation per scenario and per month of the year, as per this definition. Figure 10 shows the sum of the capacities meeting this criterion each week and presents the monthly average of this value. For the month of April, in the BCS, Baseline Flexibility scenario, the capacities on two-shift operation are relatively low, at about 4–5 GW, and are negligible through the rest of the year. Requirements for two-shifting increase somewhat in the BCS, Low Thermal Flexibility scenario, because the higher technical minimum of state-owned plants forces more plants to operate on two-shifting in order to accommodate the injection of VRE at midday.

Two-shifting requirements are highest in April in the HRES, Baseline Capacity scenario, as the higher injection of renewable energy at midday exceeds the capacity of the coal fleet to turn down below the 55% technical minimum. At this time, about 16 GW of plants must operate on the two-shifting mode, switching off early in the morning in order to respect the minimum downtime constraint and switching on in the middle of the afternoon in order to ramp up as solar output ramps down. In this scenario the two-shifting requirements range between 5 and 16 GW for several months of the year, including March, April, May, and June.

The improvement of thermal flexibility in the HRES, High Thermal Flexibility scenario decreases the requirement for two-shifting. The lower technical minimum achievable by central and IPP plants allows the coal fleet to turn down to a lower level to accommodate renewables injection at midday, without the necessity of plants operating on two-shifting. By contrast, the presence of a high two-shifting requirement in the HRES, Transmission Flexibility scenario indicates that the requirement for two-shifting is not driven by localized transmission constraints, but rather by turndown and ramping constraints operating at the level of the entire coal fleet. The addition of battery storage also substantially reduces the need for two-shifting operation, as battery absorbs the excess solar output during midday and injects it back into the grid during the evening peak, thus reducing the requirement for additional capacities to be online during the evening peak.

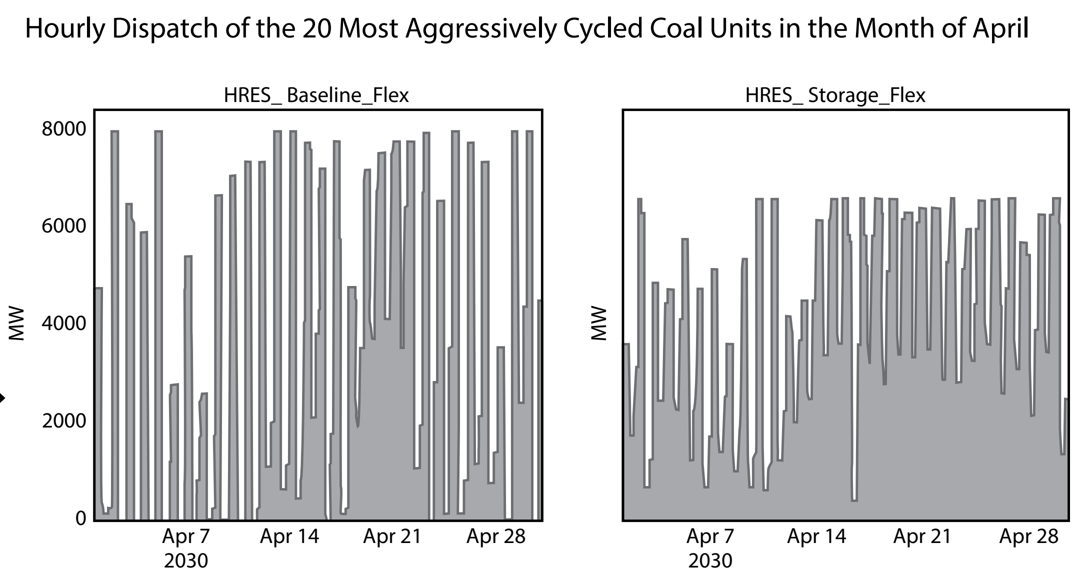
Figure 10: Required Capacities for Two-Shifting Operation by Scenario



Source: authors

In order to give a more immediate sense of the stringency of the two-shifting requirement, Figure 11 shows the aggregate hourly dispatch of the 20 most aggressively cycled coal units in the HRES, Baseline Flexibility and Storage Flexibility variants. The 20 most-cycled units operate on a two-shifting regime for most of April in the HRES, Baseline Flexibility scenario, with daily starts and stops for essentially most days of the month. The aggressiveness of the required two-shifting is much reduced in the HRES, Storage Flexibility scenario. The required peak generation from the 20 most-cycled units is both lower, and the overall profile more constant. This indicates the value of battery storage in reducing the stress on the operation of the dispatchable fleet, in particular the coal fleet.

Figure 11: Hourly Dispatch of the 20 Most-Aggressively-Cycled Coal Units

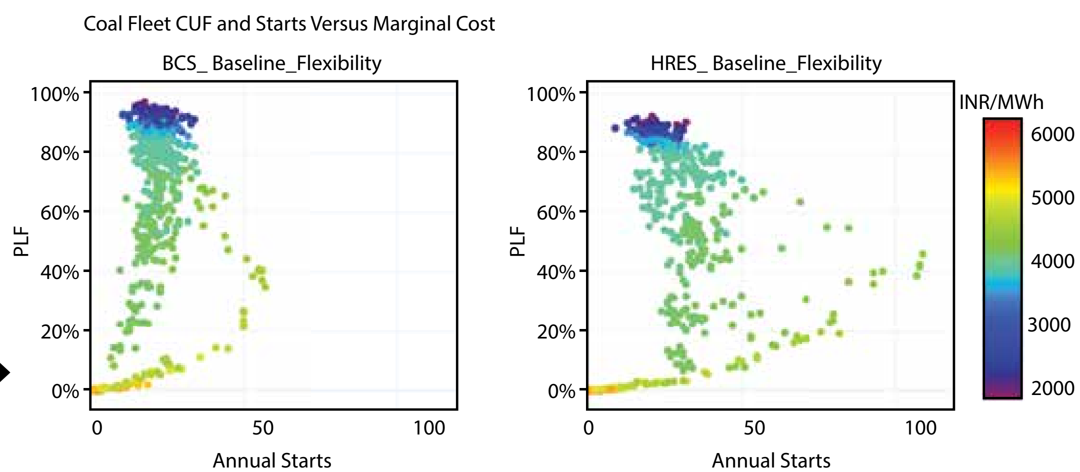


Source: authors

4.2.4 Which Coal Plants Play What Role?

In this section, we examine in a little more detail the role played by different coal-fired power plants. Figure 12 shows the unit-wise PLF, annual starts, and marginal cost for the coal fleet in the BCS, Baseline Flexibility scenario and the HRES, Baseline Flexibility scenario. The PLF is represented on the y-axis, annual starts on the x-axis, and marginal cost in the marker colour. Low marginal cost plants experience both a very high annual PLF and a low number of annual starts. On the other hand, as one moves down the merit order of marginal costs, a threshold is reached where unit-wise PLF starts to drop. Only a small number of plants have a high number of annual starts, indicating two-shifting operation, and these plants are all towards the upper third of the marginal cost curve for the coal fleet.

Figure 12: Coal Unit PLF and Starts Versus Marginal Cost



Source: authors

In other words, the model selects plants in the middle to upper third of the coal supply curve to provide flexibility in terms of low PLF load following two-shifting operation. High marginal cost plants are barely dispatched, and it may be a cost-effective strategy to retire these assets. The plants selected for two-shifting and flexible operations also vary by region. The most aggressively cycled plants tend to be located in the Northern and, to a lesser extent, in the Western and Southern regions. This is partly due to the fact that the Northern region coal units are situated towards the upper third of the coal supply curve in terms of marginal cost. It may also be due to the load profile of the states in the Northern region, with a high share of domestic and agricultural load and hence a high evening peak. This contrasts with the states of the Western and Southern region, with load profiles that often peak at midday. Less aggressive cycling of the coal fleet is therefore required in these regions to meet evening peak load.

4.2.5 Supercritical Versus Subcritical Coal Plants

Table 8 and Table 9 contain a summary of the coal fleet performance, broken down by technology (i.e. supercritical versus subcritical) and ownership class. It is noteworthy that the impact of higher VRE generation, seen in the difference between the BCS and HRES, falls largely on the subcritical plants. These display a larger increase in the number of plants falling within the PLF range of 0–20% between the BCS and HRES, with 32.2 GW under the BCS and 40.0 GW under the HRES having a PLF of 0–20%. This impact is also fairly evenly spread between state-owned and centrally owned or IPP plants.

Table 8: Coal Fleet Performance Summary by Technology and Ownership, BCS, Baseline Flexibility Scenario

PLF Range	No of Unit	Average Variable cost	Gross capacity	Sub Critical			Sup Critical		
				Total	State	Central / IPP / ISGS	Total	State	Central / IPP / ISGS
%	Nos	Rs/kWh	GW	GW	GW	GW	GW	GW	GW
0-20	107	5.4	37	32.2	11.4	20.9	5.0	2.9	2.1
20-40	33	4.5	9	7.8	1.4	6.4	1.3	0.0	1.3
40-60	69	4.4	23	17.5	3.5	13.9	5.7	1.3	4.4
60-80	116	4.2	56	21.0	6.5	14.5	35.4	12.5	22.8
80-100	204	3.3	112	34.7	12.1	22.6	77.6	23.9	53.7
Total	529		238	113	35	78	125	41	84

Source: authors

Table 9: Coal Fleet Performance Summary by Technology and Ownership, HRES, Baseline Flexibility Scenario

PLF Range	No of Unit	Average Variable cost	Gross capacity	Sub Critical			Sup Critical		
				Total	State	Central / IPP / ISGS	Total	State	Central / IPP / ISGS
%	Nos	Rs/kWh	GW	GW	GW	GW	GW	GW	GW
0-20	135	5.2	46	40.0	14.2	25.8	6.4	2.9	3.4
20-40	45	4.4	14	10.9	1.7	9.2	3.3	0.0	3.3
40-60	78	4.3	26	15.1	2.9	12.1	10.6	2.0	8.6
60-80	113	4.1	70	15.8	5.3	10.5	54.4	25.8	28.7
80-100	158	3.1	82	31.5	10.8	20.7	50.3	10.0	40.3
Total	529		238	113	35	78	125	41	84

Source: authors

4.2.6 Role of Hydro

In this section, we discuss the role of the hydro fleet in integrating VRE into the power system. Figure 13 shows the average hourly generation of the hydro fleet, distinguishing between monsoon and non-monsoon season. The hydro fleet provides substantial supply-side flexibility for the integration of VRE, providing peak support during the morning and evening, and turning down dramatically at midday in order to support the injection of solar. During the monsoon months, output is more constant across the day, consistent with the high levels of resource availability during these months. Nonetheless, output is turned down at midday essentially to the same levels as in the non-monsoon months, in order to allow for solar generation. Ensuring a high degree of flexibility and coordinated dispatch from India's hydro fleet is therefore critical to the integration of high levels of VRE.

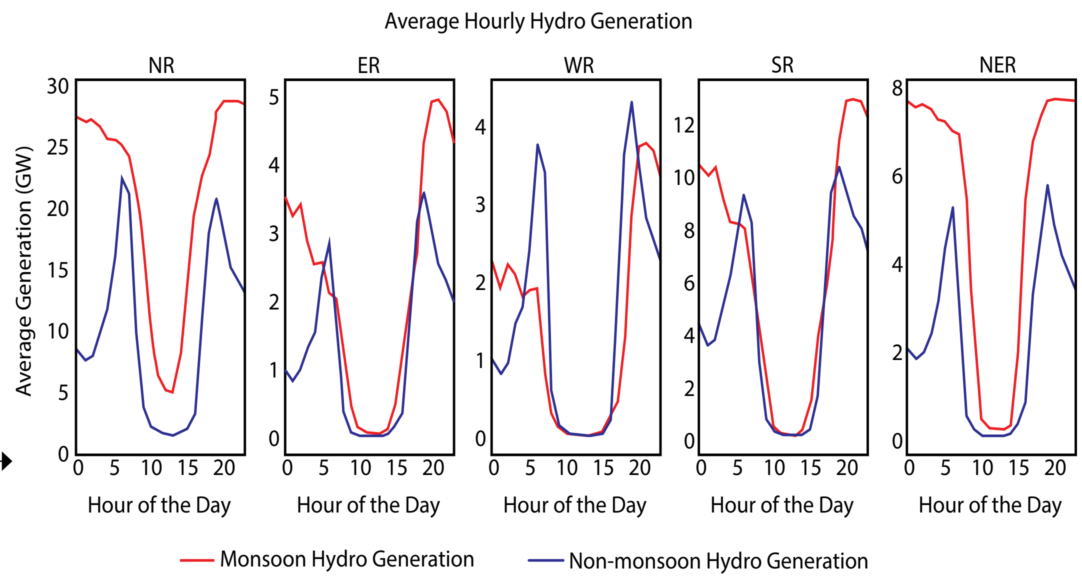


Figure 13: Average Hourly Region-Wise Hydro Generation, Monsoon, and Non-Monsoon Seasons

Source: authors

4.3 Role of Battery Storage

In the HRES, Battery Storage scenario, the model includes 60 GW, 120 GWh of battery storage facilities (see Section 3.4). In this section, we analyse how these facilities operate, and what services they play in the power system. Figure 14 shows the average hourly state of charge (SoC) of the battery facilities in the power system, by hour of the day and month of the year. SoC refers to the available energy in the battery facilities in MWh, with zero indicating that the battery facilities are fully discharged and 120,000 MWh indicating that the battery storage facilities are fully charged.[22]

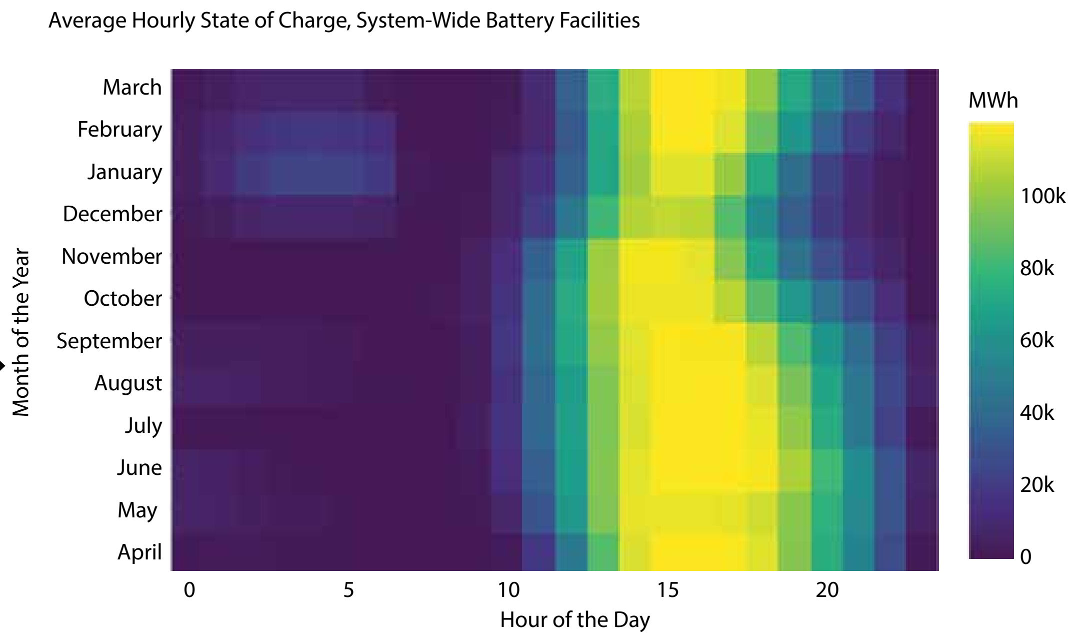
As can be seen from Figure 14, the battery facilities tend to begin the day with a zero SoC, indicating that they have discharged the previous day and have not charged in the final hours of the day. SoC tends to increase towards the midday, as the batteries assist with the integration of solar energy into the grid and reduce the need for solar curtailment, or coal plant cycling. By evening the SoC of the battery facilities start to fall, as they discharge power to provide peak support and thus reduce the need for committed coal generation to be online to meet the evening peak.

This pattern is fairly consistent across the seasons and months of the year, with only small differences seen in the winter months of the year. Here, the battery SoC increases somewhat during the very early morning hours (1:00 am to 4:00 am) and declines again during the morning peak hours (7:00 am to 10:00 pm), indicating that the batteries provide a small degree of peak

[22] It should be noted that the model is run in a series of 24 hour 'snapshots', with a 6-hour look ahead into the conditions of the following day. Thus, the model will try and optimize the operation of storage on a rolling 30-hour basis. Given that we expect battery storage to primarily play a role in intraday balancing, we do not expect that this modelling approach significantly biases the operation of storage. It would be a different case for seasonal storage, which needs to be optimized over long time periods.

support during the morning ramp from 7:00 am to 10:00 am. During the winter months, the battery facilities also tend not to reach a full state of charge during the day, as charging has a cost and during these months the full degree of daily energy shifting is not required.

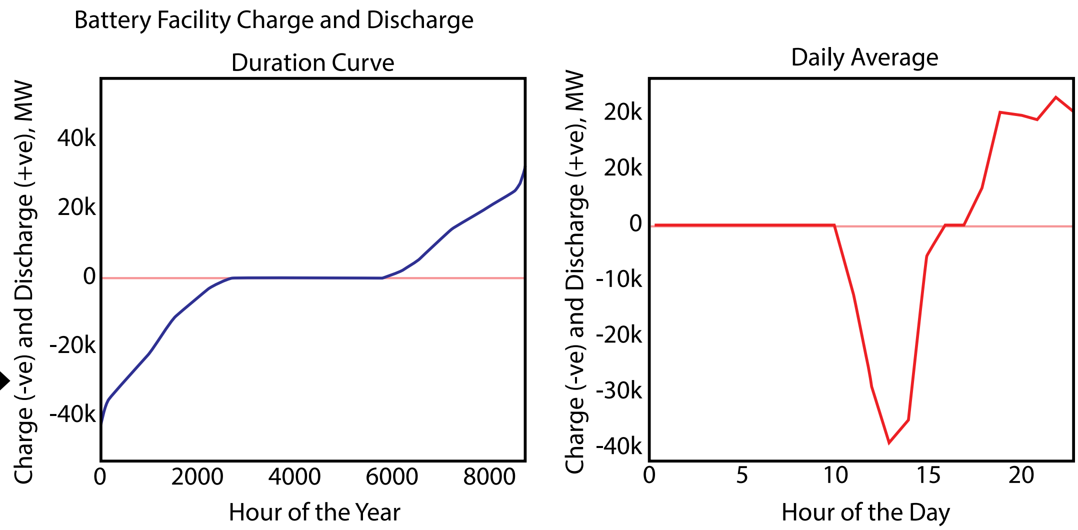
Figure 14: Average Hourly State of Change, System-Wide Battery Facilities



Source: authors

Figure 15 shows the charge and discharge curves of the battery facilities in the model for every hour of the year. In this figure, charge is displayed as a negative number, indicating that energy is being withdrawn from the grid. Discharge is shown as a positive number, as energy is injected into the grid. In Figure 15, left panel, the hours of the year are displayed sorted by the value of charge and discharge, not sequentially. Figure 15 shows that the battery facilities are required in particular to provide short-term power injections into the grid, rather than long-term energy shifting. By short-term, we mean periods of one to two hours, typically in the period 7:00 pm to 9:00 pm. In Figure 15, right panel, we show the charge and discharge summarized as a daily average, in order to show how the battery facilities operate over the course of a typical day. This panel shows how rapid the battery charging is that occurs at midday, as solar output ramps up. This suggests that the low power to energy ratio of the battery facilities in the model are determined not so much by the rapidity of the discharge required, as by the rapidity of the charge required to absorb the fast ramp up of solar output.

Figure 15: Battery Charge and Discharge Duration Curve and Daily Average



Source: authors

4.4 Interstate Power Flows

Expanding the balancing area is one of the key strategies for promoting the grid integration of VRE. This means an extension of both the physical infrastructure of the transmission system, as well as the development of the regulatory and market infrastructure to enable the transfer of electricity across long distances. This holds just as true for India, where electricity is a concurrent subject under the Constitution, meaning that legislative and regulatory competences are shared between the Centre and States. Currently, each state, or more specifically each DISCOM in a state, is responsible for scheduling and dispatching its generation resources, while interstate and interregional generating stations are scheduled and dispatched under the authority of the Regional Load Dispatch Centres and National Load Dispatch Centre. The relatively strong presence of the Centre across the electricity sector value chain, and regulatory structure, puts India in a good position to enhance the integration of the Indian grid, and strengthen the sharing of power resources across the country.

In this section, we analyse the role of the transmission system in supporting the grid integration of VRE. It is no small challenge to visualize and comprehend the role of the transmission, as the data in question occupies both spatial and temporal dimensions. Temporally, the use of the transmission system varies by time of day and season of the year, because the mix of generation resources and demand at each point in the transmission system varies across the time of the day. Spatially, it is this mix of demand and supply at each node in the system that determines the direction and magnitude of power flows along the available infrastructure. For this reason, we have provided on the online platform that accompanies this report a feature to dynamically visualize the flow of power around the country, the varying mix of generation resources, and the demand at each node at each hour of the year. Those interested in understanding more about the role of the transmission system are invited to look at the online portal in more detail.

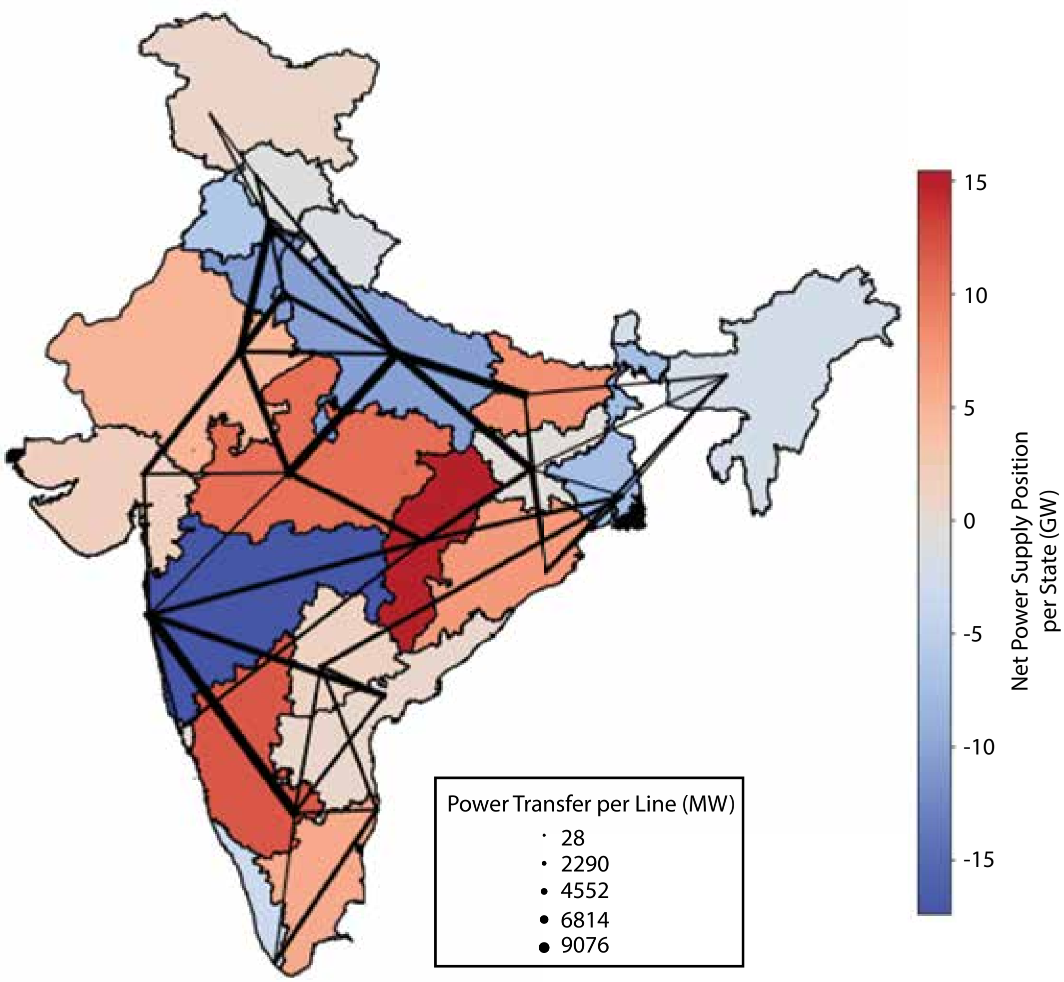
In this section, we provide a static visualization and discussion of the role of the transmission system in several representative hours of the year.

4.4.1 Summer Day

Figure 16 shows the net power supply position, in GW, of each state, and the magnitude of the power transfer, in MW, for each transmission line in our model. The representation is for one hour, selected to correspond to a period of high power transfer across the country on a summer's day. At this time of the day, solar injection is at its maximum. The colours of each state in Figure 16 correspond to the net power supply position of the state (imports net of exports). A negative number (blue) implies that the state is a net importer, while a positive number (red) indicates that the state is a net exporter. Figure 16 also shows the magnitude of the power transfer on each line, represented by the thickness of each line.

Figure 16: Power Flow per Line and Net Power Position per State, Summer Midday, BCS, Baseline Flexibility Scenario

Power Flow per Line and Net Power Position per State at 1 pm on 25-05-2030



Note: The colours represent the net power supply position for the state for the hour in question. A negative value implies that the state is a net importer, and vice versa for a positive value. The values are given by the colour map bar to the right of the plot, in GW. The lines represent the transmission lines between the states in the model. The width of the line indicates the magnitude of the flow of the line. The boxed legend gives the corresponding values for power transfer along each line, in MW.

Source: authors

As can be seen from Figure 16, the Southern Region is generally a net exporter at midday in summer, due to the high penetration of solar. Maharashtra is a net importer, due to its relatively high load, and favourable load shape for the absorption of solar (Maharashtra's load tends to peak at midday). Maharashtra also has a relatively less intra-state-generation capacities, as compared to its load. It should be noted also that imports or exports include centrally owned or IPP generating stations located beyond the state boundary. The term 'import' or 'export' thus does not refer to the contractual arrangement behind the power flow. Indeed, a substantial part of Maharashtra's power imports may be its contracted supply from out-of-state centrally owned generating stations, rather than spot or over-the-counter purchases of uncontracted supply. The coal belt of Madhya Pradesh, Jharkhand, and Odisha are net exporters of power even at midday in summer, largely to the Northern Region states of Uttar Pradesh, Haryana, Punjab, and Delhi. Rajasthan is a net exporter of power at midday, given its large solar capacities and relatively low load.

4.4.2 Summer Night

Figure 17 shows the same data points as Figure 16, except this time for a summer night. Here solar has faded to zero, and given that the hour selected falls in April, there is also relatively little generation from wind. Compared to the summer day, the picture has shifted somewhat. The Southern Region shifts to being a net importer, as its solar output has fallen to zero. The coal belt remains a large exporter, while Rajasthan and Gujarat have shifted to net imports. Net exports are provided by the hydro states, Himachal Pradesh, Uttarakhand, and the North Eastern Region. Maharashtra remains a net importer, although the scale of its net import position has moderated somewhat.

Power Flow per Line and Net Power Position per State at 9 pm on 19-04-2030

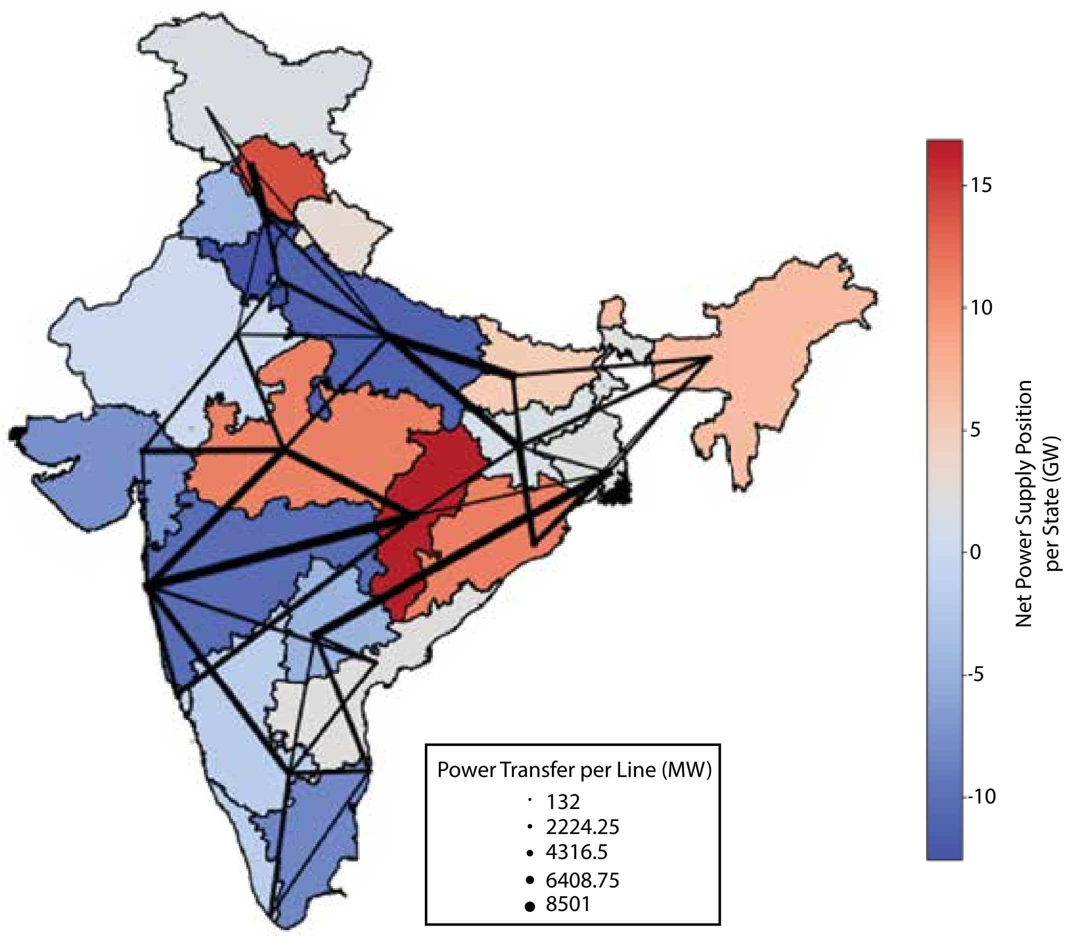


Figure 17: Power Flow per Line and Net Power Position per State, Summer Night, BCS, Baseline Flexibility Scenario

Note: The colours represent the net power supply position for the state for the hour in question. A negative value implies that the state is a net importer, and vice versa for a positive value. The values are given by the colour map bar to the right of the plot, in GW. The lines represent the transmission lines between the states in the model. The width of the line indicates the magnitude of the flow of the line. The boxed legend gives the corresponding values for power transfer along each line, in MW.

Source: authors

4.4.3 Monsoon Day

Figure 18 shows the net power supply position per state and the power flow per line for a typical monsoon day. At this time of the year, output from the wind-rich states is high, as it is from the hydro-rich states. The Southern Region, rich in wind, is a net power exporter at this time of the day, particularly from Tamil Nadu, Karnataka, and Andhra Pradesh. The coal belt is still a net exporter, particularly from Madhya Pradesh. The Northern States of Uttar Pradesh, Haryana, and Punjab are substantial net importers. Paradoxically, the high hydro states of Himachal Pradesh and Uttarakhand are net importers. This is because the timestamp selected is 13:00, when solar output is high. Even during monsoon, output from the hydro fleet is turned down at midday where possible. At night these states would show as substantial net exporters.

Power Flow per Line and Net Power Position per State at 1 pm on 24-06-2030

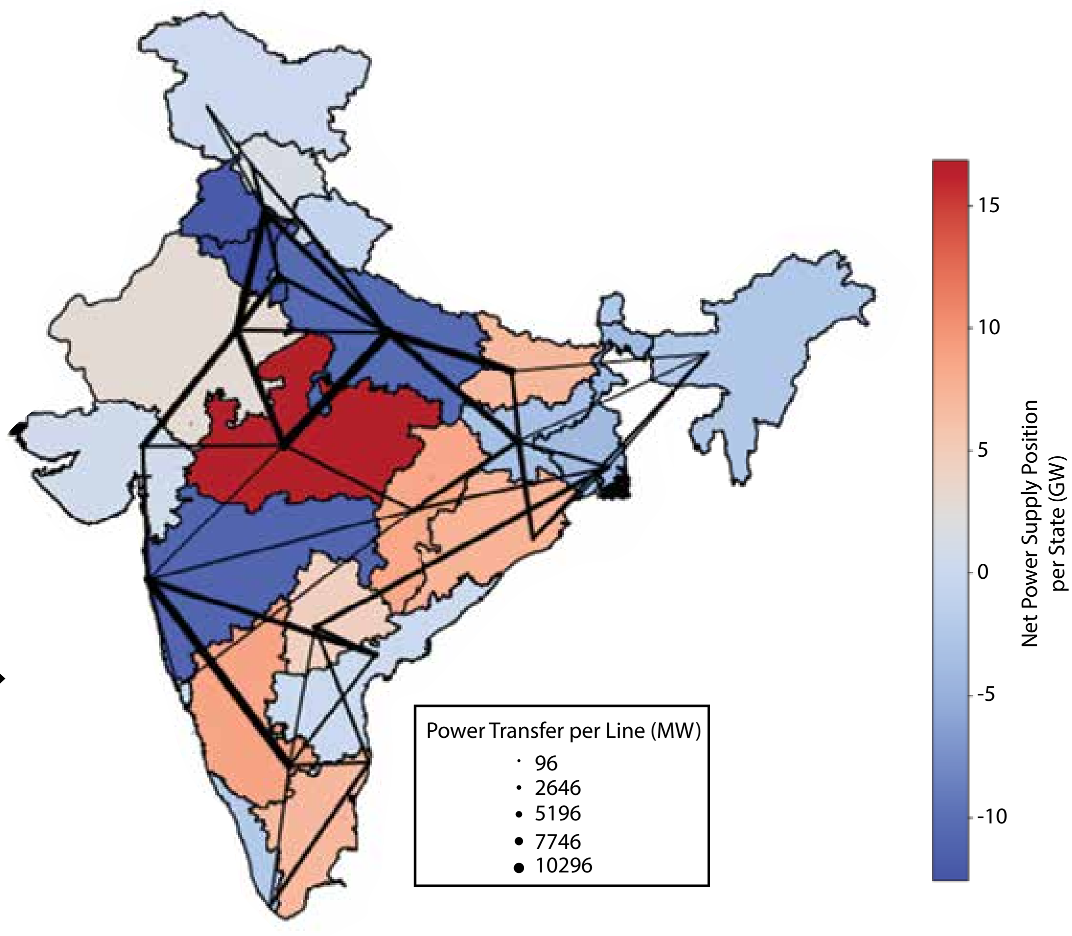


Figure 18: Power Flow per Line and Net Power Position per State, Monsoon Day, BCS, Baseline Flexibility Scenario

Note: The colours represent the net power supply position for the state for the hour in question. A negative value implies that the state is a net importer, and vice versa for a positive value. The values are given by the colour map bar to the right of the plot, in GW. The lines represent the transmission lines between the states in the model. The width of the line indicates the magnitude of the flow of the line. The boxed legend gives the corresponding values for power transfer along each line, in MW.

Source: authors

4.4.4 Discussion

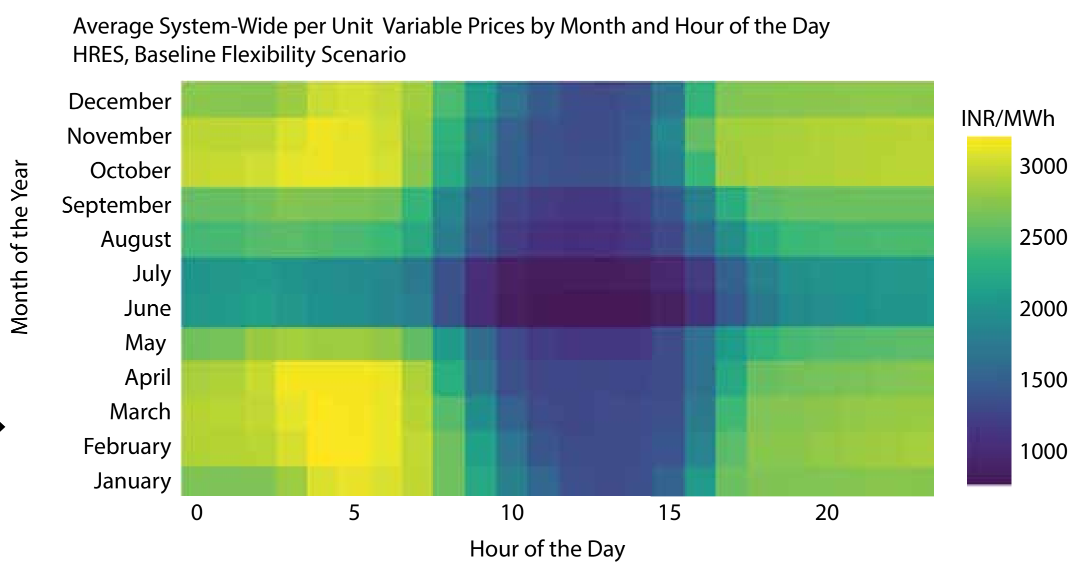
The impression that emerges is of large-scale, long-distance, and variable power flows providing significant flexibility in accommodating the variability of renewables. The daily transition of the Southern Region from exporter of solar to importer of thermal electricity is a case in point. We can get a sense of this by looking at the indicator of trade intensity for each state, defined as the sum of annual power transfers, divided by the sum of annual power transfers and state load. On this indicator, the large Southern and Western states are actually at the lower end of the spectrum, with a trade intensity of between 15% and 37%. Smaller hydro- or coal-exporting states, such as Himachal Pradesh, Chhattisgarh, Uttarakhand, and Madhya Pradesh, have even higher trade intensities, between 56% and 80%. The development of both the physical, and regulatory and market infrastructure required to enable greater levels of power transfer across the country is therefore a crucial strategy for the integration of VRE.

4.5 Marginal and Average Prices in the Power System

In this section, we analyse how the modelled average and marginal prices in the power system vary across different times of the day and different periods of the year. To begin with, several definitions are in order. Average prices refer to the sum of total variable costs divided by the output for the time period considered. Marginal prices refer to the variable cost of the most expensive generating unit dispatched to meet the last unit of load in the time period considered. Figure 19 shows the average per unit prices for the HRES, Baseline Flexibility scenario, on average for each hour of the day and each month of the year. Figure 20 shows the marginal prices for the HRES, Baseline Flexibility scenario, on average for each hour of the day and each month of the year.

Figure 19 and Figure 20 tell an interesting and important story. But it is also a complicated story, which requires careful explication. Figure 19 shows that average per unit variable prices vary substantially across different times of the day and seasons of the year. The average per unit variable prices are substantially lower during the midday hours of the day, and higher during the morning and evening periods. In addition, the average per unit prices are substantially lower during the monsoon months of June, July, August, and September. Why is this? At midday, the large injection of zero marginal cost solar substantially lowers the average per unit variable cost within the power system. Likewise, during the monsoon months, the injection of zero marginal cost wind lowers the average per unit variable cost of the power system across the monsoon months. This effect of zero marginal cost wind is more evenly spread out throughout the hours of the day than is the midday impact of zero marginal cost solar power. However, solar is also injected at midday during the monsoon months, and this combines to push the average per unit variable prices to their yearly nadir during the midday hours of the monsoon months. During these times, the average per unit variable costs even fall below 1000 INR/MWh (1 INR/kWh).

Figure 19: Average System-Wide per Unit Variable Prices



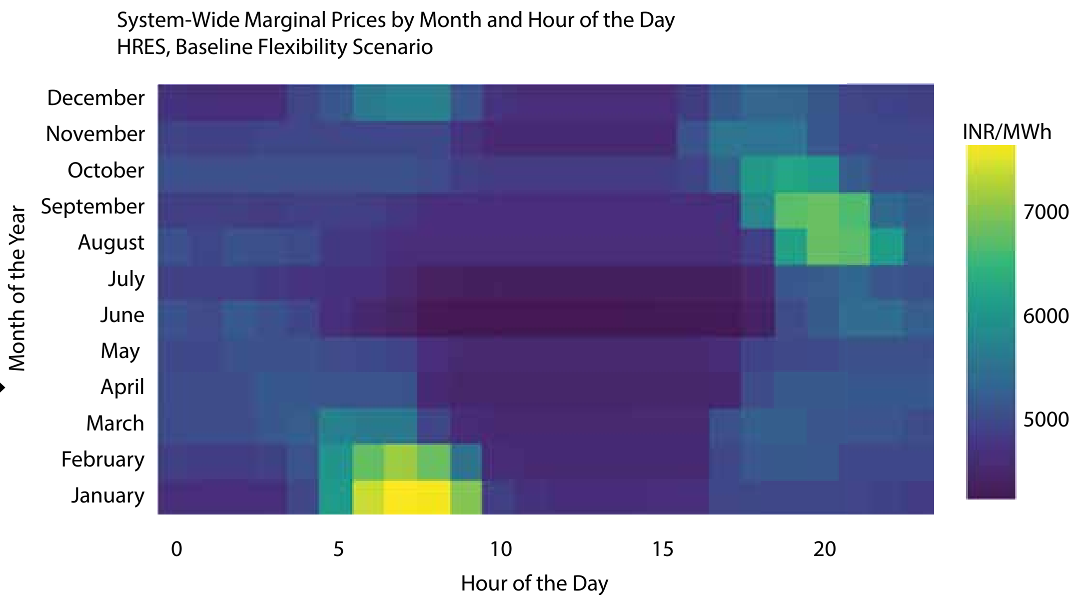
Source: authors

A more complicated and seemingly paradoxical picture emerges from Figure 20. Let us recall once again the difference between average per unit variable prices and marginal prices. Per unit variable prices represent the sum of system-wide variable prices divided by the sum of system-wide electricity generation for the time period considered. On the other hand, marginal prices represent the per unit variable price of the last (most expensive) generating unit dispatched in order to meet the last unit of load in the time period considered.

Figure 20 shows that marginal prices exhibit the same general pattern as per unit variable prices, with declines during the midday hours of the day and the monsoon months of the year. However, the magnitude of the daily or seasonal variation in marginal prices is much lower than the daily or seasonal variation of the average per unit variable prices. Between midday and morning or evening peak hours, the variability in marginal prices is less than 1000 INR/MWh (1 INR/kWh). Between the monsoon and non-monsoon months, there is a similar scale of variability in marginal prices, i.e. around 1000 INR/MWh. On the other hand, the daily and seasonal variability of average system-wide variable prices was far more substantial, in the order of 2000 to 3000 INR/MWh.

Why this difference in the variability of marginal prices and average, system-wide per unit variable prices?

Figure 20: Marginal System-Wide Variable Prices



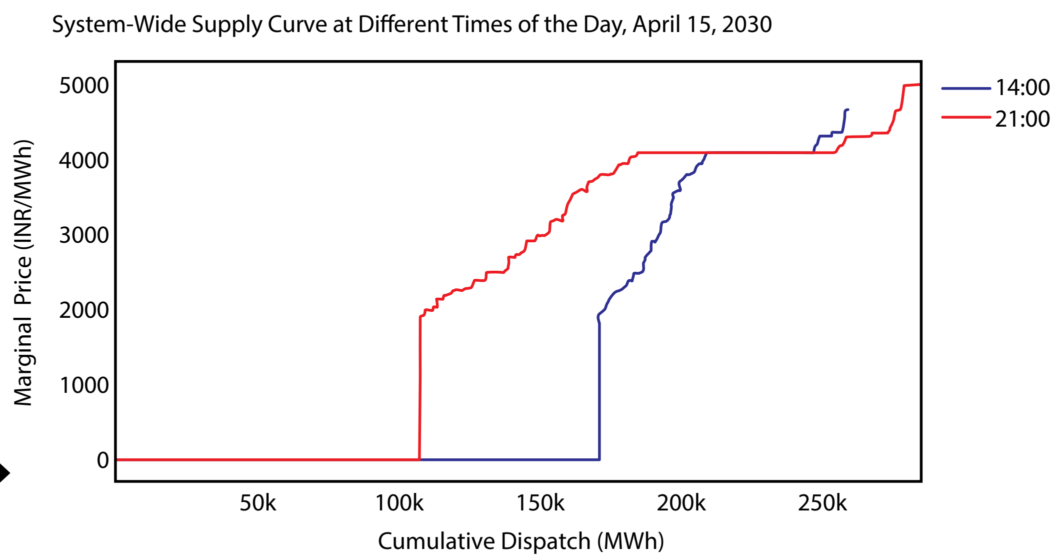
Source: authors

The answer to this question lies in the way that the model accommodates the variability of zero marginal cost renewables. The majority of the supply-side flexibility to integrate zero marginal cost renewables comes from within the supply curve, and not the end of the supply curve (economists would say that supply-side flexibility is largely inframarginal, rather than at the margin). First, the model derives substantial flexibility from the zero marginal cost hydro fleet. Second, the model flexes the segment of the coal fleet with a variable cost between ~4000–5000 INR/MWh. These are the plants that cycle up and down their output throughout the day, or shut down and start up, in order to integrate variable solar. Thus, the daily elasticity in the supply curve comes from the large middle tranche of plants, and not from the smaller tranche of high marginal cost plants. We can visualize this more directly by showing the full supply curve for two different hours in a typical day.

Figure 21 shows the system-wide supply curve on April 15, 2030, once at 2:00 pm and once at 9:00 pm. Although solar output has fully collapsed at 9:00 pm, the aggregate supply from zero marginal cost sources is only 37% lower at 9:00 pm compared to 2:00 pm. This is because zero marginal cost hydro power was turned down essentially to zero at 2:00 pm and turned up to full output at 9:00 pm. The rest of the supply-side flexibility comes from the cycling of the output of coal plants with a marginal cost of ~4000 INR/MWh (4 INR/kWh), whose output roughly doubles from 2:00 pm to 9:00 pm. By contrast, the supply from plants at the margin of the curve is broadly similar between the two periods.

The net effect of this is that the marginal price is paradoxically similar between the two periods, and varies only by 400 INR/MWh (0.4 INR/kWh). The fact that the overwhelming majority of the supply-side flexibility comes from plants within the supply curve, and not at its end, explains the lower variability of the system-wide marginal price as compared to the average per unit system-wide variable price.

Figure 21: System-Wide Supply Curves at Different Times of the Day, April 15, 2030



Source: authors

4.6 What Insights Come from the Sensitivities?

4.6.1 High Demand

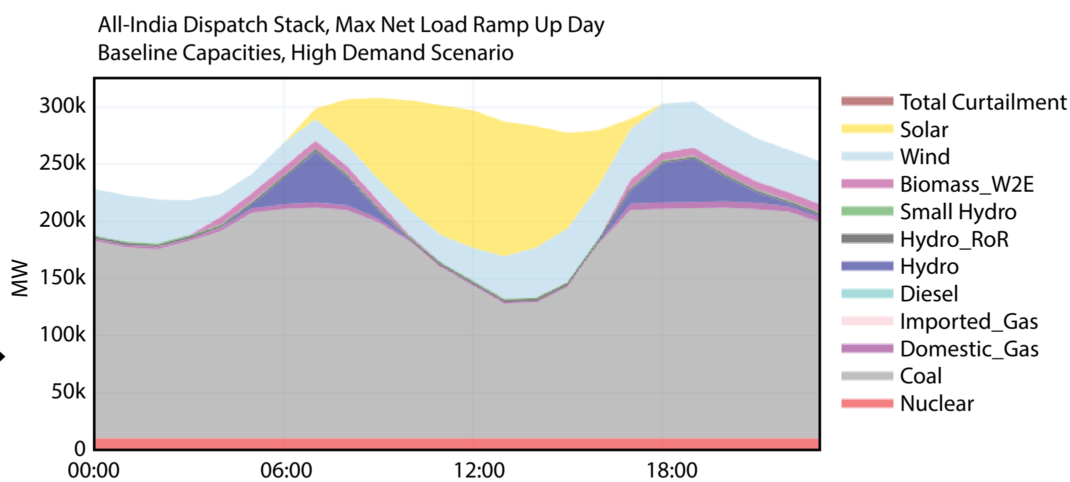
In this section, we analyse the results of the high demand sensitivity. To recall: this sensitivity builds on the BCS, Baseline Flexibility scenario, but assumes that the demand is 10% higher by 2030, compared to the demand numbers that were used in the seven headline scenarios analysed above. This extra demand is spread across the states in proportion to their share in total demand in the headline demand scenario. For each state, the extra demand allocated is spread evenly between each hour of the year in the simulation. Thus, we assume in the high demand scenario that there is no change in the shape of the load profile, compared to the baseline demand scenario.

At the aggregate level, the BCS, High Demand scenario shows a relatively small level of difference from the BCS, Baseline Demand scenarios. Unserved load in the BCS, High Demand scenario is substantially higher than in the BCS, Baseline Demand scenarios. For example, in the BCS, High Demand scenario the total load shedding is 5440 MWh, versus 117 MWh in the BCS, Baseline Flexibility scenario. By contrast, curtailment as a share of available wind and solar energy in the BCS, High Demand scenario is lower, at 0.2%, compared to the BCS, Baseline Flexibility scenario at 0.6%. This is because the larger quantum of the demand allows for the greater absorption of VRE before constraints regarding the technical minimum of the coal fleet are binding.

The extra demand in the BCS, High Demand scenario is largely met through additional coal generation, which reaches 1505 TWh, compared to 1285 TWh in the BCS, Baseline Flexibility scenario. The result of this increase is a higher coal plant PLF in the BCS, High Demand scenario, compared to the BCS, Baseline Flexibility scenario. This is because the BCS, High Demand scenario assumes the same capacities as the BCS, Baseline Flexibility scenario, and cheaper generation options like domestic gas and hydro are subject to energy constraints limiting the generation available from these sources.

Figure 22 shows the all-India dispatch stacks for the BCS, High Demand scenario. The days selected are the maximum net load ramp up day, and the maximum absolute net load day (recall that net load refers to load minus the injection of must-run VRE). According to our load profile modelling, the maximum net load ramp day occurs on January 27, 2031. On this day, the net load ramp is provided by the coal fleet, with very strong peak support from the hydro fleet. The limited energy availability for hydro, given that winter is a low hydro availability season, is concentrated in the peak morning and evening hours. Wind gives relatively little peak support at this time, given that winter is a low wind season.

Figure 22: All-India Dispatch in the BCS, High Demand Scenario, Max Net Load Ramp Day

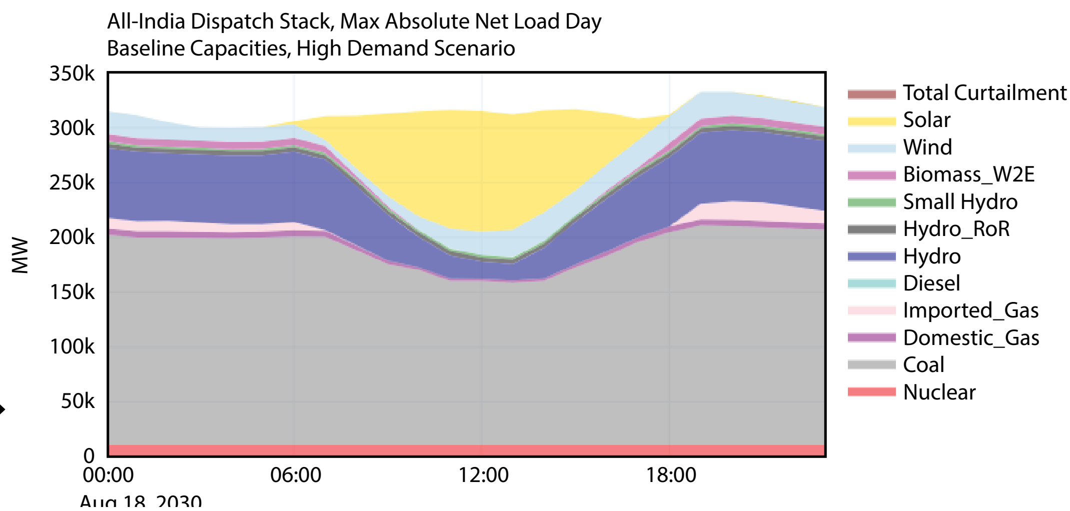


Source: authors

Figure 23 shows the all-India dispatch stack on the max net load day, which falls on August 18, 2030, according to our load profile modelling. On this day, in order to meet the high net load, the model has to draw on production from expensive imported natural gas. However, it should be noted that even in the BCS, High Demand scenario the aggregate production from imported natural gas is still low, with only 2.93 TWh being produced across the year, compared to the

0.28 TWh in the BCS, Baseline Flexibility scenario. Thus, even in the BCS, High Demand scenario, the aggregate PLF of imported gas remains low.

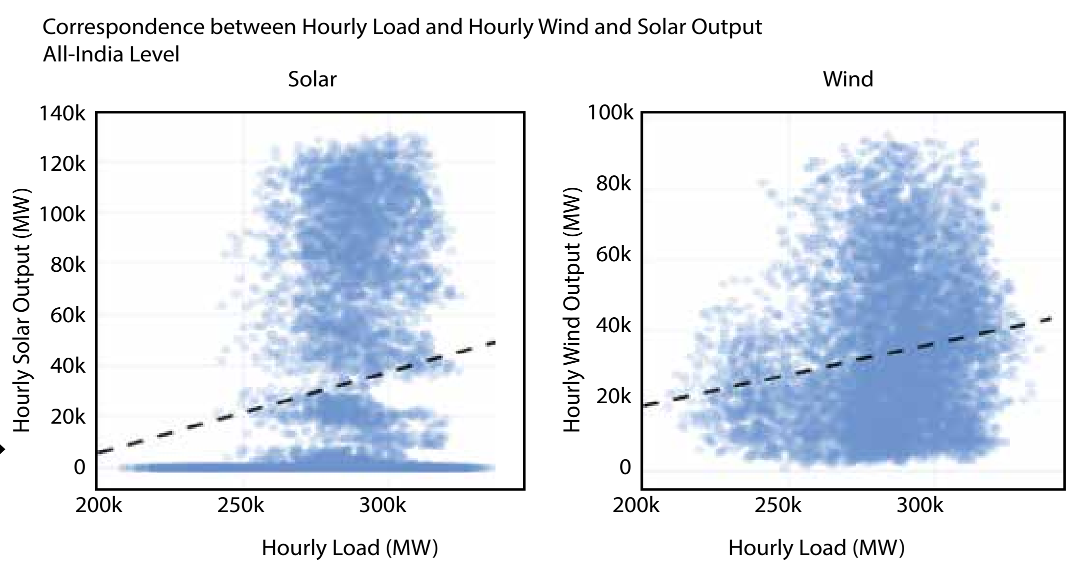
Figure 23: All-India Dispatch in the BCS, High Demand Scenario, Max Net Load Day



Source: authors

Figure 23 shows that the high net load day also has a substantial contribution in meeting the gross load from wind. However, in the real-world, wind output is stochastic, and even in monsoon the daily output of wind can vary substantially. Ideally, one would address this issue by calculating the capacity credit that one can give to wind from extensive historical data regarding the correspondence between wind output and load. Unfortunately, this historical data of renewable energy output is not available in India, which makes such an analysis challenging. However, we present the degree of correspondence between hourly wind and solar output and hourly load in Figure 24. As can be seen there is a low level of correlation between hourly wind and solar output and hourly load. This is because, in particular, gross load at all-India level tends to peak during the evening time, whereas solar is available during the day. The capacity factor of wind is low outside of monsoon periods, while gross load is often higher outside of monsoon months.

Figure 24: Correspondence Between Hourly Wind and Solar Output and Hourly Load in 2030



Source: authors

This relatively weak correspondence between wind and solar output and load creates challenges for the integration of wind and solar into the power system. At the same time, this is an area that requires further study, in particular regarding the potential evolution of the load profile to 2030 or 2050. It should also be noted that this non-correspondence between wind and solar and load holds at the all-India level. Most of the more industrialized and urbanized states tend to have load that peaks at midday, and therefore corresponds better with the output profile of solar.

4.6.2 15-minute Scenario

In the BCS, 15-minute scenario, we run the model with a temporal resolution of 15 minutes, instead of the hourly resolution that has been used for the rest of the scenarios in this report. The hourly version of the model is already highly computationally intensive, taking about 10 hours to solve with a world-class commercial solver operating on a high-performance computer. For this reason, we run the 15-minute scenario for only one week of the year. We chose, however, the week of the year, in which we find the highest net load ramping requirement in the hourly simulations of the model. This week is the last of January, from the 25th to the 30th of January.[23] The BCS, 15-minute scenario takes the same load, capacity, and flexibility assumptions as the BCS, Baseline Flexibility scenario. The two, however, cannot be directly compared, as we operate the BCS, 15-minute scenario for only one week. For this reason, the discussion thus focuses largely on the insights coming from the BCS, 15-minute scenario.

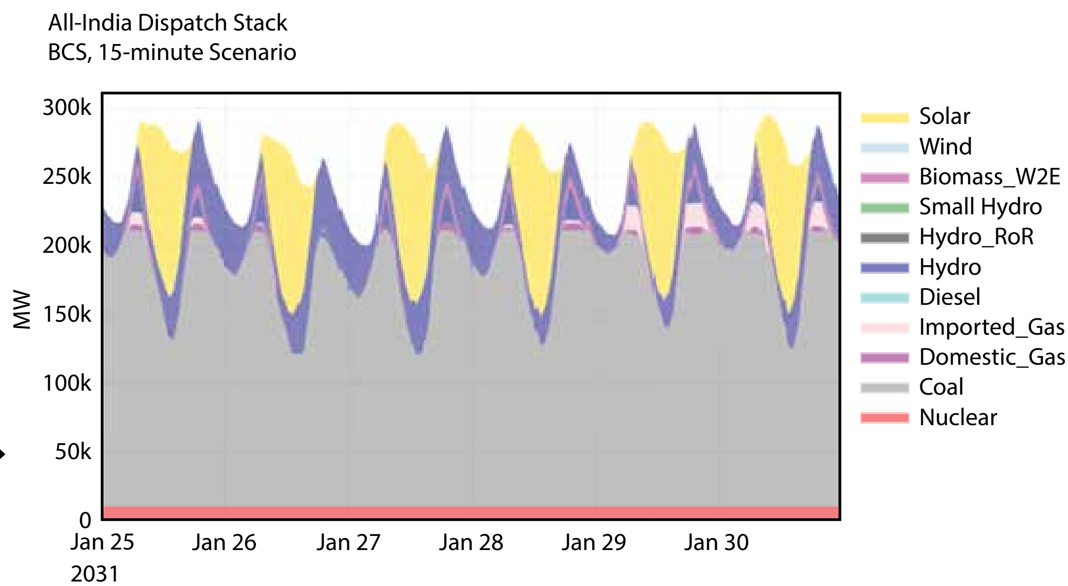
We start with some aggregate summary statistics. In all, across the week simulated, there is 33 GWh of unserved load, which is a small fraction of the 33.6 TWh of total unrestricted load across the 6 days of the total simulation. Three episodes of unserved load occurred, two in the morning between 7:00 am and 8:00 am, and one in the early evening at 6:00 pm to 7:00 pm. At these times, the model was unable to meet the rapid ramping required, albeit for only short periods of time (generally speaking, only one 15-minute block). By contrast, wind and solar curtailment was low, at an aggregate of 0.63%. This is partly because January is a low renewables period. But the combination of some unserved load and low curtailment suggests that the latter was caused by a ramping *rate* constraint not by a ramping *magnitude* constraint. If the magnitude of the available resources for ramping was the problem, then we would expect curtailment to have been higher, as renewables would have been curtailed at midday in order to allow coal plants to stay online to meet the evening peak. Across the 6 days simulated, the maximum ramp net rate up requirement was ~ 880 MW/min. The maximum net ramp rate down requirement was ~ 943 MW/min. On every day of the simulation, the maximum daily ramp up exceeded 700 MW/min. This indicates the structural challenge of increasing the flexibility of the power system in order to integrate VRE, and ensuring that all resources contribute to meeting the flexibility requirement in a coordinated manner.

Figure 25 shows the all-India dispatch stack for the BCS, 15-minute scenario, across all days of the simulation. The plot makes clear the aggressive cycling required of the coal fleet, with a ramp rate up in excess of 550 MW/min every day of the simulation. Figure 25 also makes clear the very strong peak support required from dispatchable hydro and natural gas. The model also draws more substantially on imported gas as a peaking resource than in the BCS, Baseline Flexibility scenario. This is because the extra temporal granularity exacerbates the ramping challenge, and the model

[23] We run the model actually to the end of the 31st of January, but remove the last 24 hours of the simulation (i.e. January 31), as during these hours the model is no longer constrained by expectations for the next day.

must draw on fast ramping, but expensive natural gas in order to avoid more unserved load. Dispatch of imported gas is more than a hundred times greater in the BCS, 15-minute scenario compared to the BCS, Baseline Flexibility scenario, at 1201 GWh compared to just 8.4 GWh. This suggests that part of the relatively lower PLF of natural gas in the BCS, Baseline Flexibility scenario is due to the lower temporal granularity, which obscures the intensity of the ramping challenge. It should also be noted that the value of batteries, already demonstrated in the HRES, Battery Storage scenario, would be all the greater in a scenario at sub-hourly granularity. We excluded batteries deliberately in this scenario in order to better isolate and quantify the stringency of the ramping challenge.

Figure 25: All-India Dispatch Stack, BCS, 15-minute Scenario



Source: authors

4.6.3 BCS, Low Gas Price

In the BCS, Low Gas Price scenario, we assume a lower price for imported natural gas compared to the baseline scenarios, wherein we had assumed an imported gas power tariff consistent with imported natural gas at about 10–12 USD/Mmbtu. In the BCS, Low Gas Price scenario we assumed an imported natural gas plant power tariff consistent with an imported gas price of ~ 7 USD/ Mmbtu. The objective of this scenario was to assess whether the model picked up more output from the imported natural gas plants, as a result of the lower variable cost. The answer to that question was a resounding no. The total annual output from the imported natural gas plants was 284 GWh in the BCS, Baseline Flexibility scenario, and only 288 GWh in the BCS, Low Gas Price scenario. Thus, even with a substantially lower import cost, the results suggest that imported natural gas is not competitive with the existing assets.

However, this conclusion needs to be tempered in two respects. Firstly, the results of the BCS, 15-minute scenario strongly show that natural gas may be required as a peaking fuel, when we take into account the stringency of the ramping challenge at sub-hourly level (although fast ramping batteries were excluded). Secondly, PyPSA-India, for the purposes of this study, is an operations model, not an investment model. This means that we take the power production capacities as given, notably based on the assessments of the CEA. It may be that operating new coal at partial load is less cost-effective, from a systems perspective, than extracting more output from higher variable cost, but sunk investment cost, imported natural gas plants. This is something that could be investigated in a future study.

4.6.4 Hurdle Rate

In this section, we analyse the results of the BCS, Hurdle Rate sensitivity scenario. This scenario reflects two facts. Firstly, the transmission system is not free, and its use requires the payment of wheeling charges that create, effectively, a marginal cost for power transfer. Secondly, in India's current environment of decentralized scheduling and dispatch, the institutional and market framework for substantial power transfers across the country is still being developed. On the other hand, the relative strength of the central level of governance in the Indian power sector, with the centre owning generating assets, transmission assets, and having substantial regulatory and operational duties, does create effective tools for driving the integration of India's huge power system. In order to implement the BCS, Hurdle Rate scenario, we implemented a marginal cost on power transfers across India, starting at 1500 INR/MWh for the longest interregional line, and decreasing as a function of line length relative to the longest interregional line. In this section we present an overview of the results.

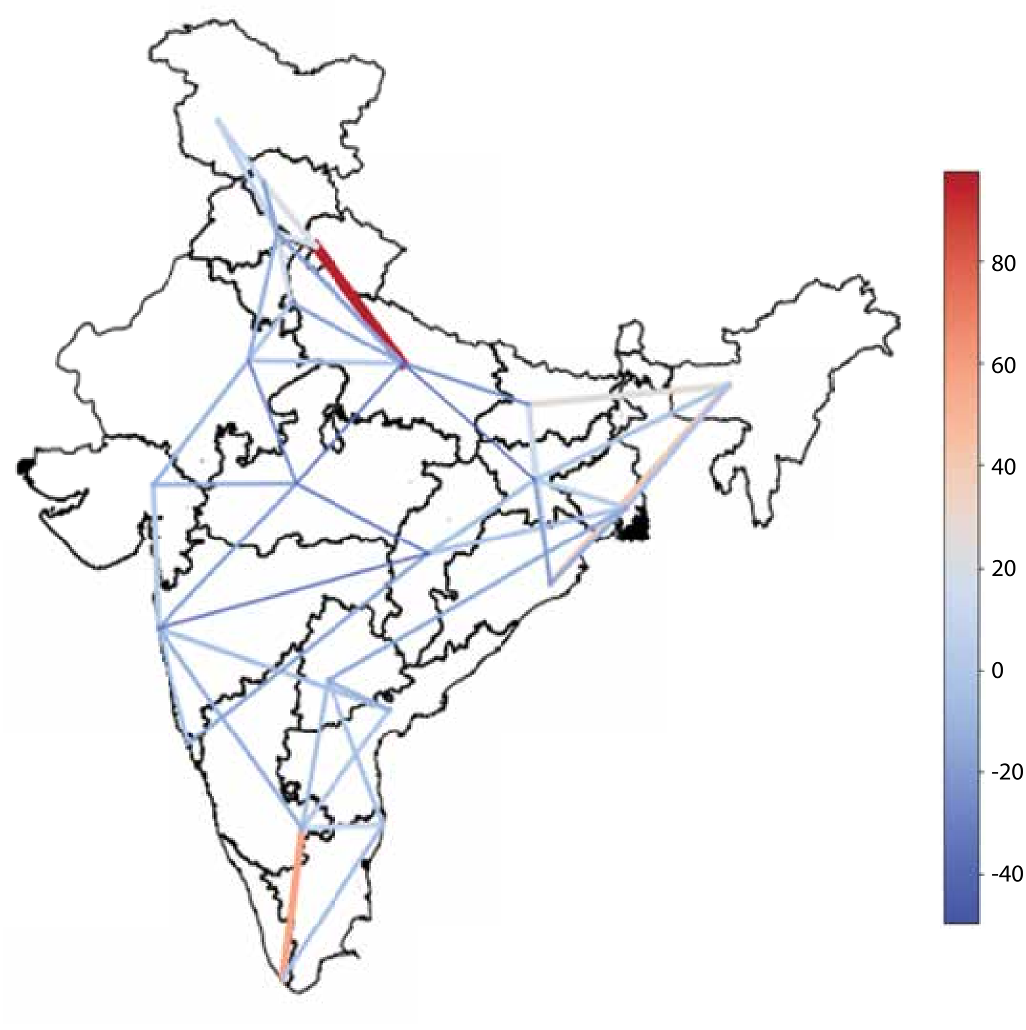
In the BCS, Hurdle Rate scenario both unserved load and curtailment increased compared to the BCS, Baseline Flexibility scenario. Unserved load reached 546 GWh (0.02% of total annual load in 2030). This compares with the current level of energy deficit of 0.5%, or 445 GWh. However, 546 GWh is still a substantial increase from the levels of unserved load in the BCS, Baseline Flexibility scenario, which reached only a hundred odd MWh. Likewise, in the BCS, Hurdle Rate scenario the levels of wind and solar curtailment increased to 0.7% and 0.9%. This is an increase compared to the BCS, Baseline Flexibility scenario, where wind and solar curtailment stood at 0.3% and 0.4%, respectively. Aggregate trade intensity, defined as the sum of aggregate power flows, divided by the sum of aggregate power flows and aggregate load, fell by 1.4 percentage points. This might seem a small adjustment, but it was nonetheless sufficient to induce the increase in unserved load and curtailment mentioned previously.

The model responds to the hurdle rate on interregional lines by increasing the flows on a number of interstate lines, as it seeks to offload power from surplus regions. In order to visualize this, Figure 26 shows the change in transmission line utilization between the BCS, Hurdle Rate scenario and the BCS, Baseline Flexibility scenario. Figure 26 shows the absolute change, i.e. the difference between the two scenarios in the sum of all power flows across the year. It is noticeable that the implementation of a hurdle rate on interregional flows redirects power flows in ways that impact beyond just the interregional lines. In particular, power flow between Uttarakhand and Uttar Pradesh increases substantially. This is because Uttar Pradesh is a deficit state, with large power imports. Sitting at the nexus of the Northern, Central, and Eastern regions, a large share of its imports is interregional. Thus, the implementation of an interregional hurdle rate raises the cost of these imports, forcing the model to source as much power as possible for Uttar Pradesh from within its own region. A similar dynamic drives the change in power flow between the NER region and Bihar and Odisha, and between Kerala and Karnataka.

Transmission pricing and the market and regulatory infrastructure facilitating transfers around the country are difficult to implement in a power systems operations model like PyPSA. The approach of using a hurdle rate is certainly crude. But the key point is simple to understand: *how sensitive is the model to changes in i) the conditions determining power flows; ii) those flows themselves*. Here we see that the model is somewhat sensitive to a moderate hurdle rate, suggesting that the large power transfers we see in scenarios without a hurdle rate are occurring at relatively small differences in locational marginal prices. Secondly, we see that indicators like lost load and curtailment are also fairly sensitive to changes in power flows, suggesting that a substantial driver of the low levels of lost load and curtailment in the BCS is the model's capacity to optimize power scheduling and dispatch over a large balancing area, free of financial constraints and limited only by the physical infrastructure in place and the impedance pathways defining the power flows. The BCS, Hurdle Rate scenario shows that substantial power transfers are a crucial strategy for facilitating VRE integration.

Absolute Change in Annual Flow per Line, BCS, Baseline Flex Versus BCS, Hurdle Rate (TWh)

Figure 26: Change in Transmission Line Utilization, BCS, Hurdle Rate Scenario Versus BCS, Baseline Flexibility Scenario



05 CONCLUSIONS AND POLICY RECOMMENDATIONS

In this section, we provide conclusions and policy recommendations based on the aforementioned analysis. It should be recalled that modelling is not the science of predicting the future, but rather the science and art of exploring complex causal relationships. A model is simply a tool for assisting the human mind in exploring these relationships with more detail, complexity, and rigour than is possible alone. In this spirit, the analysis presented in this study should be seen as an effort to understand some of the key relationships and interactions shaping the future of the Indian power sector. The conclusions and recommendations we present in this section are structured around four main topics. We deliberately step back a little from the more technical analysis of this study in order to draw higher-level policy conclusions. A summary of technical results is presented in the executive summary. In this section we permit ourselves some broader reflections on the implication of these technical results for the direction of policy in the future.

5.1 Planning for Policy, and Policy for Planning

The electricity sector is driven by the requirement to balance supply and demand at all times and all locations on the grid. The sector encompasses a very long value chain, from fuel extraction to generation, transmission, distribution, and consumption, along which different players respond to different incentives and physical constraints. The coordination of such a complex sector is crucial for its effective functioning. The growth of VRE and the increasing penetration of distribution-side energy resources such as solar PV, batteries, and electric vehicles, create an even more challenging context in which system planning must be conducted.

In this sense, planning should be seen as a mechanism for coordinating the expectations of players across the whole value chain and aligning them around a certain minimum set of assumptions and conclusions. Planning is not a discrete, one-off exercise, but rather a regular and, indeed in some sense, continuous process of absorbing and integrating new information. The impact of COVID-19 on the power sector is a case in point. It is highly likely that the demand projections of the 19th EPS, completed in 2017, are now widely off-track, given the durable impact of the COVID-19 economic crisis on GDP.[24] Thus, projections for demand and supply will need to be revised.

The implication of this uncertainty is not that planning should not be undertaken but that the way that planning is undertaken should change. Planning studies need to look at scenario ranges,

[24] In their study of the past impact of recessions, IMF economists note that countries rarely return to pre-crisis growth trends, and that recessions leave lasting economic scars. Moreover, it is the frequency of economic shocks and the permanent damage done by them that explains the failure of developing countries to catch up with developed economies. See: Cerra, Valerie and Sweta Chaman Saxena. 2017. Booms, crises, and recoveries: a new paradigm of the business cycle and its policy implications. *IMF Working Paper*.

both in order to better explore causal linkages but also to take into account the uncertainty of outcomes. Likewise, they need to become even more transparent, with freely available and easily analysable input assumptions and output results. Only this way can planning studies be interpreted for what they are: contingent explorations of complex, uncertain causal relationships interacting with the evolving, self-realising expectations of numerous players. The final implication is that planning studies need to be conducted with greater frequency than they are currently being done in India. Given the highly evolutive nature of the sector, and the rapid change of macroeconomic conditions and technology, it appears important to bring out mid-term electricity sector planning studies with a regularity of at least 2–3 years. This will allow players to regularly update their expectations and explore, in real time, the consequences of evolving assumptions. It is noteworthy that the benchmark national energy study in the US is brought out on an annual basis, and often encompasses half a dozen scenarios at least. This does not mean that policy targets are revised every 2–3 years, indeed far from it. Rather, there should be a regular updating of planning studies, within a stable framework of longer-term goals.

A corollary is that resources need to be invested in developing capacities and tools for electricity system planning. At a time when COVID-19 will strain an already financially vulnerable sector this may seem a vain hope. But investments in proper planning frameworks are just that: investments. Over the mid-term they will have returns in the form of better, more efficient investment and operational decisions.

A final implication of this focus on planning is that India needs to have a 'policy for planning'. The Electricity Act already requires the CEA to come up with a National Electricity Plan once every five years. Recent studies have marked a substantial improvement in the sophistication of the analysis of the pathway for the Indian power sector.[25] In the future, even better integration of transmission planning, VRE location, investment planning, and power system operation studies will be required.

But there is also a need to make progress in ensuring better planning at the DISCOM and state regulator level, in particular with regard to approaches to mid-term resource adequacy.[26] The amendments to the Electricity Act currently under consideration provide the opportunity to set out a 'policy for planning' appropriately structured for the different levels of governance. This should include requirements for DISCOMS to issue mid-term resource plans, and for regulators to scrutinize resource additions in the light of their own assessments of the mid-term system requirements. Given the requirements for enhanced cross-border integration, the planning framework should also encompass periodic assessments from regional load dispatch centres or regional power committees, taking a broader regional perspective to mid-term planning.

5.2 Rethinking the Centre and State Dynamics

The results of this analysis clearly show that the already high degree of integration of the Indian power system across Indian states and regions is a crucial tool for accommodating growing shares

[25] For example, CEA. 2019. Draft Report on Optimal Capacity Mix for 2029-30. New Delhi: Central Electricity Authority, Ministry of Power, Government of India. Details available at http://cea.nic.in/reports/others/planning/irp/Optimal_generation_mix_report.pdf

[26] See Singh, Daljit and Ashwini K. Swain. 2018. Fixated on Megawatts: Urgent Need to Improve Power Procurement and Resource Planning by Distribution Companies in India. CEER {AQ: Place of publication.}.

of VRE. In many ways, India is blessed in having a relatively strong central level of governance, with the federal government owning and operating assets in the generation and transmission sectors and having a national-level system operator in POSOCO. More devolved federal systems, like the US or Europe, would probably envy India its degree of centre–state integration in the power system.

At the same time, the challenge of growing the share of VRE increases the need for short-term resource sharing between states, and, with that, the need to consider interstate interactions in planning for resource additions. In our analysis, the median trade intensity (defined as the sum of imports and exports over the sum of imports, exports, and load) among Indian states is almost 50%, implying a high level of interstate power transfer and coordinated scheduling and dispatch. It seems unlikely that the current process of DISCOM self-scheduling and dispatch can lead to this degree of interstate transfers in a coordinated manner.

The CERC has proposed a redesign of the day ahead market in India, shifting away from self-scheduling and dispatch towards a market-based economic dispatch based on a common pool of bids and offers.[27] This proposal certainly moves in the right direction, although it is likely to require a number of years before it could be implemented. It is necessary to consider interim steps, such as the enforcement of gate closure, mandatory sharing of un-requisitioned surplus, and potentially regional approaches to scheduling and dispatch.

The increased requirement for interstate integration also suggests that there is a need to rethink the dynamics between centre and states. This does not mean that more centralization is necessarily required in all domains, indeed far from it. But state-level actions in terms of power system operation and planning should be considered in the context of potential spillovers to other states and the all-India level. There should be an effort to increase the transparency of scheduling and dispatch decisions at state level: while these remain the prerogative of state-level decision makers, the need for cooperative federalism in the power sector will only increase as VRE drives up the need and complexity of interstate power system integration.

5.3 Driving Power System Flexibility

Coal

Our analysis suggests that substantial flexibility will have to come from the coal fleet. The BCS, Low Thermal Flexibility scenario showed a substantial increase in the risks of curtailment with decreasing thermal plant flexibility. Today, while stations falling under the jurisdiction of the CERC are mandated to achieve a 55% technical minimum, state-owned stations do not face such a requirement. Analysis of state-level dispatch, where data is available, and interstate generating station dispatch data[28] suggests that much of the current, relatively small, burden of supply-side flexibility is being foisted upon the interstate generating stations. As the share of VRE grows, this will not be tenable, and the state-owned generating stations will need to contribute to system

[27] For the CERC proposal moving towards Market-Based Economic Dispatch across the country, see CERC. .2018. Discussion Paper on Market Based Economic Dispatch of Electricity: Re-designing of Day-ahead Market (DAM) in India. Details available at http://www.cercind.gov.in/2018/draft_reg/DP31.pdf

[28] This data is available from the regional load dispatch centres.

flexibility. Given the jurisdictional limitations of CERC, driving this requirement will not be easy. But increasing the transparency around state-level scheduling and dispatch, and plant performance, can also increase the understanding of how the burden of supply-side flexibility is being shared among different players in the system. Certainly, it seems difficult, if not impossible, to reach the Government of India's ambitious 2030 renewables targets with the current level of supply-side flexibility from the state-owned plants.

Batteries

The degree of flexibility required from the coal fleet is potentially challenging to meet, and perhaps the real advantage of battery storage in the next few years will be in reducing the operational stress on the power system. The analysis presented here suggests that an aggregate energy capacity of about 120 GWh, with a relatively low power to energy ratio of 2, would have substantial benefits in terms of reducing curtailment and the aggressive cycling required of the coal system. The analysis also suggests that the requirement for storage would really begin to bite in our HRES. In the BCS, curtailment and metrics such as maximum hourly ramp rate or capacity required for two-shifting appear more manageable. This suggests that the development of battery capacities should be seen as a mid-term investment, preparing the power system for greater shares of VRE thereafter. The analysis presented here, however, does not allow us to quantify the many other benefits of battery storage technology, which depend on use cases that are difficult to model in an operations model.

5.4 Future Work and Data Requirements

Developing the PyPSA-India model and conducting this study have shed light on the challenges for this kind of analysis in the current Indian context. There are a number of big lacunae in this study that need to be remedied in future work. In particular, the absence of a stochastic representation of load and VRE generation makes impossible to quantify reliability metrics for the scenarios assessed here. As the share of VRE increases, modelling studies based on the representation of the full range of variability in renewables production and load are imperative to give confidence in the security of supply of the capacity scenarios developed. Currently in India, long, publicly available timeseries of load, weather, and renewables production are not available. Gathering these datasets and making them available to the broader research community will be a crucial step forward. In order to prompt this level of transparency, TERI is making the result datasets from this study available free for download, and we hope others in research, academia, and government will follow suit.

A second lacuna is related to the integration of the investment and operations perspective. 2030 is still 10 years away, and thus at the limit of the time horizon where purely operational modelling is an appropriate approach. Going forward, developing publicly available datasets on the transmission system, load profiles and end-use profiles, as well as renewable resource availability, will be essential to allow the development of sophisticated capacity expansion models and their integration with operational models. This is an area on which TERI intends to work in the future.

ANNEX

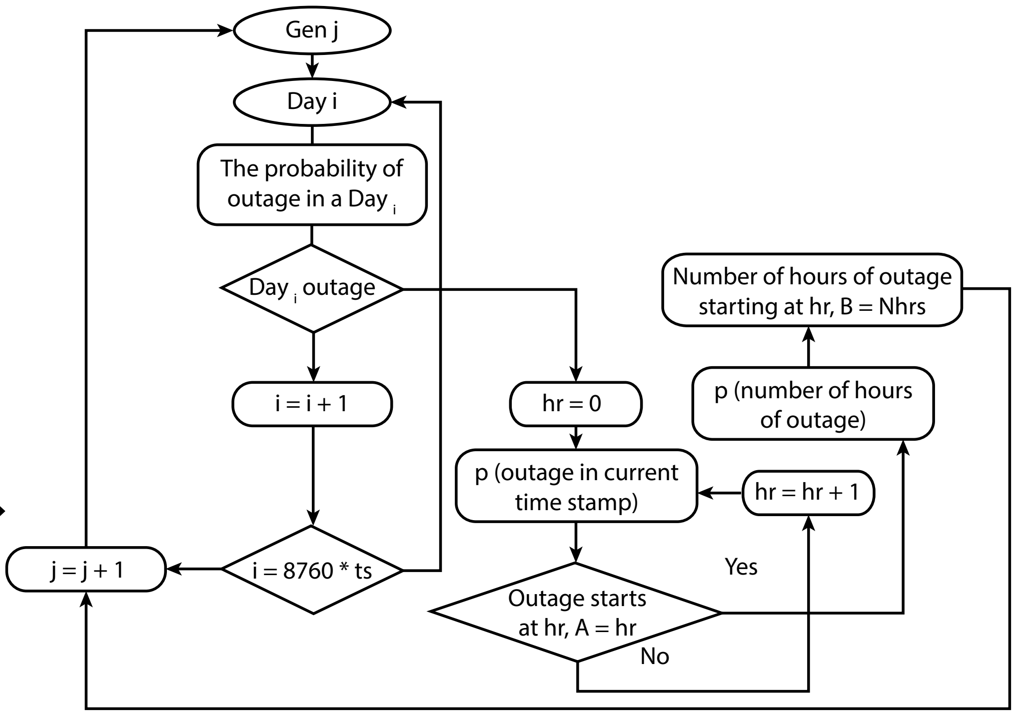


Figure 27: Conceptual Framework for the Simulation of Forced Outages

Table 10: Summary of State-Wise Load Forecasts

State	Energy Requirement (TWh)	Peak Load (GW)	State	Energy Requirement (TWh)	Peak Load (GW)
Delhi	52.22	10.60	Maharashtra	300.60	41.98
Haryana	124.16	20.88	Andhra_Pradesh	120.84	19.15
Himachal_Pradesh	16.73	3.16	Karnataka	111.72	19.18
Jammu_Kashmir	21.13	2.95	Kerala	42.28	6.94
Punjab	97.19	23.94	Tamil_Nadu	185.66	27.21
Rajasthan	123.27	20.82	Bihar	38.29	6.58
Uttar_Pradesh	256.76	39.96	Jharkhand	56.88	8.18
Uttarakhand	27.78	5.53	Odisha	36.26	6.15
Chhattisgarh	45.35	6.85	West_Bengal	84.22	15.46
Gujarat	206.07	31.43	Telangana	134.87	21.37
Goa	6.48	1.15	NER	33.41	6.17
Madhya_Pradesh	137.79	26.91			

Table 11: Summary of Inter-state Transmission lines Capacity in Baseline and HRES in the Model

Inter State Transmission Line name	s_nom_Baseline(MVA)	s_nom_HRES(MVA)
Andhra_Pradesh_Karnataka	2057	2275
Bihar_Jharkhand	4228	4228
Bihar_Odisha	12336	12336
Bihar_NER	11838	11838
Delhi_Uttar_Pradesh	20492	20492
Odisha_NER	4326	4326
Goa_Chhattisgarh	4554	4523
Gujarat_Maharashtra	6109	6109
Gujarat_Madhya_Pradesh	8486	8486
Haryana_Delhi	16777	16777
Haryana_Himachal_Pradesh	9494	9494
Haryana_Rajasthan	18266	18266
Haryana_Uttar_Pradesh	18407	18407
Haryana_Uttarakhand	3408	3408
Himachal_Pradesh_Haryana	2690	2724
Himachal_Pradesh_Jammu_Kashmir	1241	1843
Jharkhand_Chhattisgarh	5812	5812
Jharkhand_Odisha	16928	16928
Jharkhand_NER	2877	2877
Jharkhand_West_Bengal	2334	2705
Karnataka_Kerala	3190	3296
Karnataka_Tamil_Nadu	4761	4761
Maharashtra_Andhra_Pradesh	5179	6767
Maharashtra_Chhattisgarh	19763	19763
Maharashtra_Gujarat	3456	3988
Maharashtra_Goa	4047	4171
Maharashtra_Karnataka	9076	11025
Madhya_Pradesh_Chhattisgarh	20928	20928
Madhya_Pradesh_Maharashtra	23386	23386
Odisha_West_Bengal	4362	4396

Inter State Transmission Line name	s_nom_Baseline(MVA)	s_nom_HRES(MVA)
Punjab_Haryana	18065	18065
Punjab_Himachal_Pradesh	15384	15384
Punjab_Jammu_Kashmir	6196	6196
Punjab_Uttar_Pradesh	4298	4971
Rajasthan_Delhi	5840	6567
Rajasthan_Gujarat	6186	7690
Rajasthan_Madhya_Pradesh	7063	7470
Rajasthan_Uttar_Pradesh	8478	8478
Telangana_Andhra_Pradesh	14651	14651
Telangana_Karnataka	9850	9850
Telangana_Tamil_Nadu	9477	9477
Tamil_Nadu_Kerala	7270	7270
Uttar_Pradesh_Bihar	37873	37873
Uttar_Pradesh_Jharkhand	6500	6500
Uttar_Pradesh_Madhya_Pradesh	20839	20839
Uttar_Pradesh_Uttarakhand	18175	18175
Uttarakhand_Himachal_Pradesh	2642	3458
West_Bengal_Chhattisgarh	17444	17444
West_Bengal_NER	2394	2550
West_Bengal_Telangana	8498	8506

For more information

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