ENERGY AND INNOVATION AT IFP ENERGIES NOUVELLES

IFPEN ECONOMIC PAPERS

IFP SCHOOL - IFPEN

Nº 164

JANUARY • 2026

RESEARCH

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Transition to Net-Zero: How Future Electricity Demand Shapes India's Power Sector Decarbonization Pathways

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Abstract

India faces the dual challenge of decarbonizing its power sector while meeting rapidly growing electricity demand. Electricity consumption is projected to nearly triple by 2040, while the power sector accounted for about 54% of national energy-related CO_2 emissions in 2023. Recognizing this issue, the Indian government pledged at COP26 to achieve net-zero emissions by 2070. Transitioning to a low-carbon power system is a long-term and capital-intensive process, where assumptions about future electricity demand play a central role. This paper examines how optimal investment strategies for decarbonizing India's power sector by 2070 vary under alternative demand scenarios. To this end, a dynamic, bottom-up linear optimization model of the Indian power system has been developed, which simultaneously determines the least-cost hourly dispatch and optimizes investment in generation and storage capacities for each decade from 2023 to 2070. Three electricity demand scenarios are considered, representing distinct development pathways for India based on GDP evolution. Results indicate that while wind and solar dominate capacity growth, dispatchable thermal technologies remain essential for system flexibility and reliability. Achieving net-zero emissions requires full deployment of nuclear, hydro, while coal with carbon capture and storage (CCS) plays a critical role after 2060, especially under the high-demand scenario. However, the required deployment rates, particularly for wind, nuclear, and CCS, exceed historical levels, raising feasibility concerns without significant demand-side efficiency gains and lower transmission losses.

Keywords:
Power System Modeling, Electricity Demand, Net-zero transition, Indian power sector

1. Introduction

Developing countries face the dual challenge of achieving decent living standards while decarbonizing their economies [1]. Economic development typically entails higher electricity consumption, driven by industry electrification and rising ownership of household appliances [2]. At the same time, the decarbonization process relies heavily on electrification across sectors, further amplifying electricity demand in countries where power generation remains predominantly carbon-intensive [3]. This challenge is particularly acute for India, the world's third-largest CO_2 emitter, whose power sector accounted for about 54% of national energy-related CO_2 emissions in 2023 (IEA). Electricity generation remains heavily dependent on coal, which represented 73% of the generation mix in 2023 [4]. Since greenhouse gas (GHG), and particularly CO_2, emissions are key drivers of climate change [5], India has announced ambitious climate targets at COP26: increasing its non-fossil fuel capacity to 500 GW by 2030 and achieving net-zero emissions by 2070[1], among other goals [7]. At the same time, India is the world's most populous country with a rapidly expanding economy [8], and even though, India's per-capita electricity consumption remains comparatively

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[1] Limiting global warming to 1.5°C requires achieving net-zero CO_2 emissions worldwide by around 2050 [6]. In contrast, India has committed to achieving net-zero emissions by 2070, underscoring its historically limited contribution to global greenhouse gas emissions and its substantial energy requirements to sustain economic development [7].

low, at 1,057 kWh per person, compared with 1,758 kWh in Southeast Asia and 6,060 kWh in China [9], electricity consumption is projected to increase substantially in the coming decades. According to the IEA [2], demand could reach between 2,980 and 3,433 TWh by 2040, up from 1,207 TWh in 2019, driven by growing ownership of household appliances, especially cooling systems, and the electrification of industrial processes. This uncertainty widens considerably over longer horizons: by 2070, demand projections range from 3,070 TWh in the lowest scenario of [10] to as high as 12,800 TWh in the scenario presented by [11].

Developing a low-carbon power sector is a long-term and capital-intensive process, in which assumptions about future electricity demand play a central role [12]. Whereas electricity demand in developed countries is relatively stable and largely exogenous, developing countries have greater scope to influence demand trajectories. Governments can shape future consumption patterns through energy-efficiency measures [13], and policies aimed at expanding reliable and affordable access to electricity. Assessing optimal pathways for power system decarbonization therefore requires a comprehensive approach that integrates long-term demand scenarios with detailed power system modeling.

To the best of our knowledge, long-term electricity demand projections for India remain relatively underexplored in the academic literature. A first strand of studies focuses directly on forecasting electricity demand, often emphasizing the role of energy-efficiency improvements and additional load arising from the adoption of electric vehicles and expanded air-conditioning use. For example, [14] project state-level, regional, and national electricity demand for 2042 using a Partial End Use Methodology that accounts for transmission and distribution losses as well as emerging loads such as green hydrogen production. Their results suggest that national electricity demand could reach 3,423 TWh by 2042. Similarly, [15] estimate 2050 electricity demand using a custom regression model that incorporates bottom-up projections of cooling and transport electrification. Their scenarios range from 3,320 TWh under a low-growth pathway with strong air-conditioning efficiency improvements to 5,680 TWh under a high–GDP growth trajectory. A second strand of the literature develops long-term demand scenarios as part of broader assessments of India's future energy and power system. The India Energy Security Scenarios (IESS), developed by NITI [16], present four narratives ranging from "little effort" to "extremely aggressive" policy action to characterize possible evolutions of energy demand and supply by 2047. In their analysis of the power sector, electricity demand in 2047 varies from 5,254 TWh in the Determined effort scenario and 6,033 TWh in the Net Zero scenario. Likewise, [17] analyze transition pathways to 2050 across multiple scenarios that address uncertainties on both the demand and supply sides. They examine two electricity demand trajectories which incorporate efficiency improvements across sectors and electrification in transport, hydrogen production, and residential cooking. Their estimates place electricity generation requirements in 2050 between 5,246 TWh in the Baseline scenario and 4,985 TWh in the Low-Carbon scenario. Although the projected levels of future electricity demand vary across studies, they consistently agree that India's electricity demand will rise substantially in the coming decades.

While the literature on electricity demand appears to be limited, numerous prospective studies focusing on India's power system decarbonizing have been carried out by both public authorities and academic researchers. On the public-authority side, the Central Electricity Authority (CEAu) released a study in 2020 [18] identifying the least-cost optimal mix of power generation capacities needed to meet peak demand in 2030. This analysis was updated in 2023 [19], in the aftermath of the COVID-19 crisis, incorporating revised assumptions about demand growth, particularly peak demand, and improved geographical detail. They found that 56% of the 2,441 TWh demand of 2030 might still be covered by fossil fuel technologies, while renewable energy sources (RES) account for 41% and nuclear for the remaining 4%. Batteries are also expected to play an increasingly important part in electricity generation. The important role of batteries is underlined as well in the analysis of [20], who extend the study by examining least-cost trajectory for India's power system up to 2047. The authors found that by 2047, variable renewable energy (VRE) resources make up 58% of installed capacity and supply 54% of total electricity, with no curtailment, as surplus generation during low-demand periods is stored and dispatched during peak hours. Finally [10] go further by providing a comprehensive assessment of India's optimal energy mix to achieve carbon neutrality by 2070 under different economic growth scenarios. Their analysis focuses on the integration of nuclear power and hydrogen into the energy mix and finds that net-zero emission can be achieved only if a substantial amount of nuclear generation, ranging from 78 GW to 331 GW depending on the scenario, is added to the mix by 2070.

Likewise, a growing body of academic research investigates the optimal energy mix for India's power system in the near future. While much of the literature has concentrated on identifying the least-cost mix under higher shares of renewable energy sources ([21], [22], [23]), India's pledge at COP26 to reach carbon neutrality by 2070 set a clear target and has since driven research on the feasibility of achieving this goal. [24] analyze the role of different technologies and energy efficiency in decarbonizing India's power system by 2050–2060, aiming for economy-wide carbon neutrality by 2070. They find that solar PV, onshore and offshore wind, and battery storage dominate the generation mix, with wind and solar accounting for 85%–90% of total capacity, supported by battery and pumped storage. [11] similarly explore decarbonization pathways, comparing nuclear and renewable integration while including additional electricity demand from green hydrogen. Their results indicate that the total transition costs are largely independent of the chosen pathway, with installed capacity growing from 373 GW in 2020 to 6,300–9,500 GW by 2070. However, unlike these studies, [25] consider the limitations of renewable energy potential. They emphasize that achieving net-zero by 2050 is feasible only with the inclusion of carbon capture and storage (CCS) to overcome the renewable energy limitations. Their analysis further shows that targeting 2050 incurs an additional cost of INR 14.51 trillion but provides the benefit of reducing cumulative CO_2 emissions by 19.16 $GtCO_2$.

Across these studies, which employ bottom-up long-term capacity expansion models, a consistent finding is the increasing role of intermittent renewable energy sources in decarbonizing India's power system. Capturing the variability of these resources, however, requires models with high spatial, temporal, and technical resolution. As a result, researchers have focused on developing long-term models with a high level of technical definition. An important improvement in modeling has been the shift from representing India as a single aggregated system ([11], [24]) to considering its regionalized power structure. Some studies divide the country into five regions ([25], [26], [21], [22]), corresponding to the five interconnected grids, while others, such as [20], model the power system at the state level with detailed balancing regions. This approach allows for a more accurate representation of the transmission system and the spatial distribution of generation, capturing, for example, the high concentration of renewable resources in southern India. Second, many studies emphasize hourly optimization to capture the intermittency of renewable energy sources, rather than relying on aggregated time slices [20], which group hours by similar electricity demand levels. For studies modeling decarbonization pathways up to 2070, the use of representative weeks or days was often necessary to reduce computational complexity ([25], [11], [24], [26], [21]). In contrast, [22], focusing on the optimal capacity mix for 2040 only, optimized across all 8,760 hours of the year.

Considerable effort has been devoted to capturing the variability of renewable energy sources at high temporal and spatial resolution. For instance, [21] partitioned India into grid cells to integrate high-resolution renewable energy data, allowing for detailed assessments of land availability and the hourly generation potential of solar and wind resources. Similarly, [25] derive representative solar and wind generation profiles for each Indian region using GIS and 41 years of MERRA-2 data. In parallel, significant attention has been given to short-term operational flexibility, such as unit commitment ([22], [11], [24], [26], [21]). Finally, several recent studies broaden the technological scope of decarbonization pathways by incorporating hydrogen and nuclear [11], carbon capture and storage ([25], [24]), and battery storage technologies.

All these studies develop detailed models of the Indian power system but overlook how differing long-term demand levels shape decarbonization strategies. Due to the significant uncertainty surrounding India's future electricity demand, these studies consider a broad range of final demand values, as summarized in Table A.7 of Appendix A. By 2050, projected demand ranges from 3,406 TWh to 9,000 TWh, with an average of approximately 5,100 TWh. For 2070 this range is even larger, with the minimum and maximum demand estimates being 3,070 TWh and 12,800 TWh, respectively. Among them, only three studies explicitly incorporate multiple long-term demand scenarios into their analysis ([11], [26], and [10]). [11] examine India's 2070 power-sector decarbonization strategy using an hourly power system optimization model that also captures short-term operational characteristics. They consider two end-use demand scenarios: a business-as-usual case in which electricity demand reaches 7,900 TWh and does not achieve net zero, and a high-electrification scenario with demand rising to 12,800 TWh, which includes an additional 83 Mt of green hydrogen demand to achieve net-zero emissions by 2070. They explore how different nuclear deployment pathways affect the generation mix under the Net-Zero demand level. Their results indicate that the overall transition cost shows low sensitivity to the technology choice, as higher fuel expenditures in a nuclear-intensive pathway are compensated by higher capital investment in a renewable-dominated pathway. Despite formulating two demand scenarios, the authors evaluate all Net-Zero pathways under a single demand level.

In a comparable approach, [10] develop seven scenarios to assess least-cost electricity mixes by 2070 under low, medium, and high economic growth. Electricity demand is primarily driven by GDP and, in the medium and low-growth cases, demand peaks around 2050 before declining by 2070 due to efficiency gains and sectoral demand reductions. Among the seven scenarios, the authors evaluate three nationally determined contributions (NDCs) scenarios, aligned with a 33–35% reduction in emissions intensity by 2030 and a 40% renewable-energy share target by

2030; and four Net-Zero variants emphasizing, respectively, nuclear power, fossil fuels with CCUS, renewable energy, and an integrated NZ-2070 pathway. As in [11], all four NZ scenarios are examined under the same medium-growth demand projection. Taking a different perspective from above works, [26] analyze how structural changes in India's demand profile could impact the power system by 2050. Their analysis focuses on demand-side interventions, such as improved air-conditioning efficiency standards and alternative electric-vehicle charging strategies, and shows that even rapid deployment of solar and wind, combined with efficiency improvements, is insufficient to reduce annual CO_2 emissions in 2050 relative to 2020. Importantly, this study varies the shape of the load rather than the level of final electricity demand.

From this literature, several research gaps emerge regarding the decarbonization of India's power system. First, most studies rely on a single assumed trajectory for future electricity demand, especially in Net-Zero scenarios, rather than accounting for a range of possible demand levels. Second, only a limited number of studies examine the optimal electricity mix required to achieve net-zero emissions by 2070 while explicitly considering the constraints on renewable generation potential.

Our study builds on existing research on India's power sector decarbonization by incorporating three long-term electricity demand scenarios into the modeling framework. This allows us to assess how total electricity generation costs vary across different demand pathways and to evaluate technology investments required to decarbonize India's power system by 2070. In particular, the model accounts for region-specific renewable energy potentials and captures technological improvements in renewable technologies over time. Specifically, we develop a dynamic, bottom-up linear optimization model of the Indian power system. The model simultaneously determines the regional least-cost hourly dispatch to balance electricity supply and demand, while optimizing investments in generation and storage capacities for each decade from 2023 to 2070. Optimal power mixes are analyzed under the three alternative electricity demand trajectories, within a net-zero emissions pathway. The results indicate that, while wind and solar dominate capacity expansion across all scenarios, their intermittency and regional saturation effects imply a persistent need for dispatchable thermal technologies, with coal with CCS playing a key balancing role, particularly in Net-Zero pathways. Moreover, achieving carbon neutrality by 2070 requires large-scale deployment of nuclear, hydro, and CCS at rates far exceeding historical levels, and especially under high demand scenario.

The rest of the paper is organized as follows: Section 2 presents the Indian power sector and Section 3 describes the methodology, scenarios and the major assumptions while Section 4 presents the results. Eventually, Sections 5 and 6 are devoted to the discussion of results and the conclusion.

2. Indian Power Sector's Particularity

The Indian power system is organized not at the national level but across five interconnected regions; North, West, South, East, and Northeast, as illustrated in Figure 1. As of March 2023, India's total installed capacity was 399 GW (Figure 1), with 52.74% coming from thermal sources (coal and lignite), 11.7% from hydro, 6.23% from gas, 1.7% from nuclear, and 0.13% from diesel utilities [27]. Renewable energy sources[2] accounts for 27.51% of total installed capacity. In particular, solar energy, including rooftop installations, is the most developed renewable source, accounting for 13.5% of the total installed capacity in 2023. Wind power follows at 10.1%, while biomass contributes 3% [27]. Notably, although coal constitutes 49% of the installed capacity, it generates 73% of the total electricity, making India's power system highly carbon-intensive.

India's diverse climate and topography result in significant variations in installed capacity and generation mix across regions (Figure 1). The Northeastern region, near the Himalayan range, have a generation mix that is over 30% hydro, while states in the Eastern region rely primarily on coal, accounting for almost 90% of their mix. Additionally, over 40% of the total renewable energy generation is concentrated in the Southern region: Karnataka (17%) and Tamil Nadu (14%), two Indian southern states gather almost a third of the renewable installed capacity [27], [4].

[2]excluding hydro

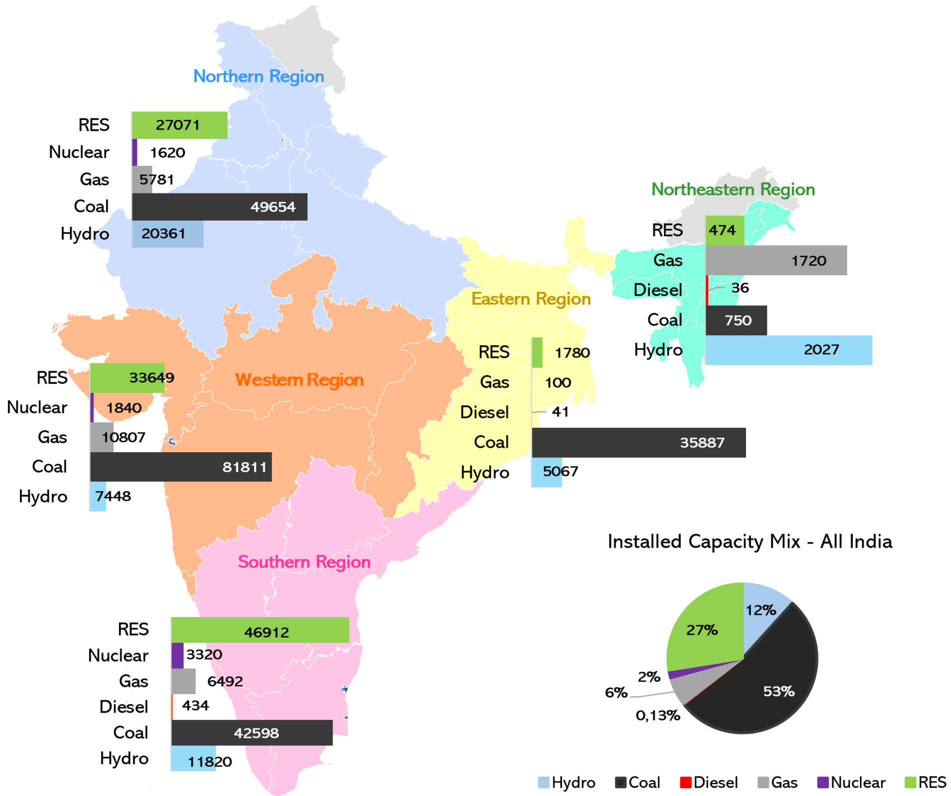


Figure 1: Regional and National Installed Capacities (MW), March 2023
Note: The figure presents the regional energy mix in MW and the national installed capacity mix in percent as of March 2023.
Source: Author's figure Data: [27]

Imports and exports of electricity with neighboring countries represent only a small percentage, respectively 0.53% and 0.65%, of the 1,423 TWh of electricity produced in India in 2021-22 [27]. India is a net exporter of electricity since 2016-17 and exchanges electricity with four of its neighboring countries, Bhutan, Bangladesh, Nepal and Myanmar. It imports mainly from Bhutan and exports mainly to Bangladesh. At the regional level, electricity exports remain relatively low, accounting for a maximum of 6% of total electricity production in the Eastern region, which primarily trades with Bangladesh [4].

Even though most of the electricity is currently produced thanks to coal, the Indian government made significant environmental commitments at COP21, which were further strengthened at COP26, to decarbonize the power sector. Two key targets directly relate to the development of renewable energy: India aims to achieve 500 GW of non-fossil energy capacity by 2030 and meet 50% of its energy needs from renewable sources by that year, with the ultimate goal of reaching net-zero emissions by 2070 [28].

3. Methodology, Data and Scenarios

The specific characteristics of the Indian power system are integrated when designing the model. Since electricity planning remains centralized, the perspective of the central planner is adopted and the Indian power system is modeled as five distinct and interconnected power systems. This regional approach provides a framework that improves modeling accuracy by accounting for regional disparities, as electricity demand and the installed capacity mix vary significantly across regions. For now, electricity exchanges with neighboring countries are not modeled, as they account for only a small share of total electricity generation.

3.1. The Model

India's power system is represented by a model that performs dynamic linear optimization with a bottom-up approach. It defines the least-cost electricity generation mix and investment decisions to satisfy electricity demand starting in 2023 and then for each ten years from 2030 to 2070. It considers India as five nodes and minimizes annualized power system costs for each region, with the possibility of inter-regional transmission and storage. The model accounts for fixed and variable operating costs, as well as investment and fuel costs. The key decision variables are the optimal hourly electricity generation mix (in MWh), and the investment decisions, represented by additional capacity in generation (in MW) and transmission each year. The modeled technologies encompass coal and gas power plants, nuclear reactors, solar photovoltaics (PV), onshore wind, hydropower, biomass, and storage options including batteries (4h) and hydro pumping stations (PSP). In addition, coal-fired generation equipped with CCS is introduced into the analysis starting in 2030. Finally, several hypothesis are made. First, electricity from non-utility and captive power plants is excluded from the analysis. Second, there is no uncertainty over the exogenous electricity demand. Third, for computational tractability, the model is formulated as a linear optimization problem. As noted by [29], introducing non-linear constraints could improve accuracy but would considerably increase computational requirements. The model is implemented in GAMS (General Algebraic Modeling System) and solved using CPLEX.

3.1.1. The Objective Function

The objective function, shown in Eq. 1, minimizes the inter-annual inter-regional total cost (TC) which is the sum over all the periods of the regional total costs ($TC_{t,r}$) with inter-regional transmission allowances. It includes the sum of fuel costs for each hour, season and technology type, and annualized investment in capacity and transmission for each technology and region. Finally, it also accounts for electricity storage, investments in transmission capacity and power exchanges between regions. The model's variables represent the power supplied by each technology of type (i) for every hour (h) and season (s) throughout the year (t) and for region (r). (k) represents the set of storage technologies: pumping storage stations and batteries.

$$
\begin{aligned}
TC = \sum_t \sum_r (1+\beta)^{-t} \Big[& \sum_s \sum_h \sum_i V_{t,r,i} \cdot P_{t,r,s,h,i} \cdot H_{r,s,h} + \sum_s \sum_h \sum_f \phi_{t,f} \cdot \mathrm{F}_{t,r,s,h,i,f} \\
& + \sum_s \sum_h \sum_k V_{t,r,k} \cdot (Store^{+}_{t,r,s,h} + Store^{-}_{t,r,s,h}) \cdot H_{r,s,h} \\
& + \sum_i (K_{t,r,i} + fOM_i) \cdot \mathrm{C}_{t,r,i} + \sum_k (K_{t,r,k} + fOM_k) \cdot \mathrm{C}^{Store}_{t,r,k} \\
& + \frac{1}{2} \sum_{r_j} \lambda_t \cdot \mathrm{T}_{t,r,r_j} \cdot \delta_{r,r_j} + \sum_s \sum_h (\theta_t + \zeta_{t,r}) \cdot \mathrm{M}_{t,r,s,h} \cdot H_{s,h} \\
& - \sum_s \sum_h \zeta_{t,r} \cdot \mathrm{X}_{t,r,s,h} \cdot H_{s,h} \Big]
\end{aligned}
\tag{1}
$$

In which we have the following variables: $P_{t,r,s,h,i}$ represents the power supplied to the grid in MW and $F_{t,r,s,h,i,f}$ the fuel quantity (MMBtu) used to produced electricity. $Store^{+}_{t,r,s,h}$ ($Store^{-}_{t,r,s,h}$) is the electricity needed to store electricity (resp. produce electricity) in MW. $C_{t,r,i}$ is the total installed capacity (MW), T_{t,r,r_j} is the investment in transmission line (MW) and finally $M_{t,r,s,h}$ and $X_{t,r,s,h}$ are the total power bought (resp. sold) to another region in MW.

The parameters are as follow: β is the discount rate, $V_{r,i}$ is the variable cost of production (lakh[3] ₹/MWh), $H_{s,h}$ is the length of the season, ϕ_f is the fuel price for (lakh ₹/MMBtu), $K_{t,r,i}$ is the fixed cost (lakh ₹/MW), defined as the sum of annualized CAPEX (Equation 17), while fOM_i represents the fixed Operation and Maintenance costs. λ_t is the investment cost of new transmission lines (lakh ₹/MW), δ_{r,r_j} is the distance between region (km), θ_t is the transmission cost (lakh ₹/MWh) and $\zeta_{t,r}$ is the electricity price (lakh ₹/MWh).

The cost-related parameters are summarized in the Tables 1 to B.8.

[3]Indian unit, corresponds to 10^5

3.1.2. Operational Constraints

The model is subject to constraints that ensure system feasibility. It enforces a supply-demand equilibrium for each hour, with no allowance for unmet demand.

Demand Constraints.

Specifically, in each region and for each hour of every season and year, the total electricity supplied by power plants, bought from other regions, and turbine-generated power must meet or exceed the sum of demand, the electricity sold to other regions, and the electricity required for storage.

$$\sum_i P_{t,r,s,h,i} + M_{t,r,s,h} + \sum_k Store^{-}_{t,r,s,h,k} \geq D_{r,h,s} + X_{t,r,s,h} + \sum_k Store^{+}_{t,r,s,h,k} \quad (2)$$

with $D_{r,h,s}$ being the electricity demand in MW.

Supply Constraints.

For each technology, and at every hour of each season and year, the load has to be lower than the power capacities once taking into account the seasonal capacity factor of each technology.

$$P_{t,r,s,h,i} \leq C_{t,r,i} \cdot \tau_{r,i} \quad (3)$$

With $\tau_{r,i}$ being the capacity factor for each technology.

Capacity Constraints.

Installed capacities are determined endogenously, and depend on initial exogenous capacities, optimal investments defined by the model, and decommissioning based on technology life-cycles; with the exception of hydro, whose capacities are assumed not to be decommissioned.

$$C_{t,r,i} = InitC_{r,i} \cdot \kappa_{t,i} + \sum_{t-\Lambda_i}^{t} I_{t,r,i} \quad (4)$$

With $InitC_{r,i}$ being the initial installed capacity (in MW), $\kappa_{t,i}$ the closing rate of initial capacities, Λ_i the operational lifetime (in years) and $I_{t,r,i}$ the additional capacity (in MW).

Investment Constraints.

To more accurately represent feasible investment pathways, installed capacities at each time step are constrained by technology-specific upper bounds. These thresholds are derived by estimating the maximum potential capacity for each technology and specifying corresponding investment growth rates. The detailed methodology is presented in Section 3.2.4.

$$C_{t,r,i} \leq MaxI_{t,r,i} \quad (5)$$

With $MaxI_{t,r,i}$ the upper limit of investment.

Fuel Constraints.

Electricity generated with fuels for each year, season, hour and technology depends on the quantity of fuel used and their efficiency.

$$\sum_f F_{t,r,s,h,i,f} \cdot \alpha_{f,i} = P_{t,r,s,h,i} \cdot H_{s,h} \quad (6)$$

With $\alpha_{f,i}$ the fuel efficiency by technology.

Ramping Constraints.
Equations 7 represents the speed at which electricity production (in MW) can decrease or increase from one hour to the next.

$$P_{t,r,s,h,i} - P_{t,r,s,h-1,i} \leq \rho_i \cdot C_{t,r,i} \quad \text{and} \quad P_{t,r,s,h-1,i} - P_{t,r,s,h,i} \leq \rho_i \cdot C_{t,r,i} \tag{7}$$

ρ_i, represents the ramping rate (in %) specific to each technology.

Transmission Constraints.
Installed transmission capacities are determined endogenously, and depend on initial exogenous capacities, optimal investments defined by the model, and decommissioning process based on technology life-cycles.
For the first year:

$$I^{tran}_{t_1,r,r_j} = InitT_{r,r_j} \tag{8}$$

For each following year:

$$T_{t,r,r_j} = \sum_{t-\Lambda_{tran}}^{t} I^{tran}_{t,r,r_j} \cdot \gamma_{r,r_j} \tag{9}$$

With $InitT_{r,r_j}$ is the initial transmission capacity, Λ_{tran} the operational lifetime of transmission lines (in years), I^{tran}_{t,r,r_j} the additional transmission capacity installed per year in MW and γ_{r,r_j}, a parameter that allows investment only in border regions.

Storage Constraints.
Equation 10 represents the minimum and maximum storage capacity of storage devices per region, where $C^{stock}_{t,r,s,h,k}$ is the current potential in MW. Equation 11 describes the evolution of $C^{stock}_{t,r,s,h,k}$, allowing electricity production $Store^{-}_{t,r,s,h,k}$ or electricity consumption for pumping and water storage $Store^{+}_{t,r,s,h,k}$. The parameter η accounts for inefficiencies, meaning that more electricity is required for pumping water than what can be effectively produced. To avoid the computational burden associated with binary variables that distinguish charging and discharging modes, we add a small cost penalty to discourage simultaneous charging and discharging.

$$0.1 \cdot C_{t,r,k} \leq C^{stock}_{t,r,s,h,k} \leq C_{t,r,k} \tag{10}$$

$$C^{stock}_{t,r,s,h,k} = C^{stock}_{t,r,s,h-1,k} + \eta \cdot Store^{+}_{t,r,s,h-1,k} - \frac{Store^{-}_{t,r,s,h-1,k}}{\eta} \tag{11}$$

Power Exchanges between Regions.
Equations 12 to 15 define the constraints governing electricity exchanges between regions, ensuring that imports and exports are consistently balanced and remain within the capacity limits of the transmission network.

$$\sum_{r} X_{t,r,s,h} = \sum_{r} M_{t,r,s,h} \tag{12}$$

$$X_{t,r,s,h} = \sum_{r_j} X^{intra}_{t,r,r_j,s,h} \quad \text{and} \quad M_{t,r,s,h} = \sum_{r_j} M^{intra}_{t,r,r_j,s,h} \tag{13}$$

$$X^{intra}_{t,r,r_j,s,h} = M^{intra}_{t,r,r_j,s,h} \tag{14}$$

$$M^{intra}_{t,r,r_j,s,h} \leq T_{t,r,r_j} \tag{15}$$

Equation 12 means that, for every hour, season and year, national exports $X_{t,r,s,h}$ must equal national imports $M_{t,r,s,h}$. Equation 13 means that at each point of time, export of region r $X_{t,r,s,h}$ (resp. imports $M_{t,r,s,h}$) is the sum of the exports $X^{intra}_{t,r,r_j,s,h}$ (resp. imports $M^{intra}_{t,r,r_j,s,h}$) realized with all the other regions r_j. Equation 14 means that exports from region r to region r_j are equal to imports of region r_j from region r. Equation 15 specifies that imports between regions must be lower or equal than what transmission capacities $TrCap_{t,r,r_j}$ can carry.

CO_2 emission constraints.
Lastly, annual CO_2 emissions can be capped under a certain threshold, here CO_2Lim.

$$\sum_r \sum_s \sum_h \sum_f F_{t,r,s,h,i,f} \cdot \alpha_{f,i} \cdot \chi_f \leq CO_2Lim_t \tag{16}$$

With χ_f the tonnes of CO_2 quantity per fuel type and CO_2Lim the national CO_2 yearly emission limit.

3.2. Supply Data

3.2.1. Economic Inputs

Since the optimization of installed capacity is cost-driven, selecting appropriate fixed and variable costs is crucial for making informed decisions. Table 1 summarizes the techno-economic characteristics of the thermal power plants and renewable capacities used in the model. The capital expenditure (CAPEX) and fixed operation and maintenance (O&M) costs are sourced from the report on "*Synchronizing energy transitions toward possible Net Zero for India*" by [10]. For variable costs, the data are taken from [30] and converted into rupees using the average 2023 exchange rate between the Indian rupee and the US dollar, namely 1 USD = 83 ₹. Fuel cost data of domestic coal, uranium and biomass comes from the study of [22], while imported coal and domestic and imported gas are extrapolated from [24]. In the case of coal with CCS and batteries, costs are assumed to increase linearly with installed capacities. Table 1 also presents the lifespans, for all technologies, and availability factor for non-intermittent technologies. Availability represents the amount of time where the plant is able to produce electricity over a certain period, divided by the amount of the time in the period. Both lifespans and availability factors comes from [19] and [18]. Thermal efficiency, representing the amount of MWh generated per MMBtu of each fuel, are displayed in Appendix B.

Technology	CAPEX (lack ₹/MW)				Fixed O&M (lack ₹/MW)				Variable O&M (lack ₹/MWh)				Fuel Cost	Lifetime	Availability
	2023	2030	2050	2070	2023	2030	2050	2070	2023	2030	2050	2070	(₹/MMBtu)	(years)	(%)
Hydro	830	826	823	823	20.75	20.65	20.58	20.58	0	0	0	0	-	40	-
Solar	544	390	227	227	5.44	3.9	2.27	2.27	0	0	0	0	-	25	-
Wind	666	624	591	591	6.66	6.24	5.91	5.91	0	0	0	0	-	25	-
Biomass	500	500	483	483	10	10	9.66	9.66	0.004	0.004	0.004	0.004	300	20	60
Nuclear	1,500	1,500	1,500	1,500	43	43	43	43	0.002	0.002	0.002	0.002	82	30	80
Coal	830	830	830	830	20	20	20	20	0.008	0.007	0.007	0.007	24	25	88
Gas	500	478	464	464	18	18	18	18	0.006	0.006	0.006	0.006	295	25	90
Coal/CCS	1,494	1,494	1,328	1,328	33	33	29	29	0.013	0.012	0.012	0.011	248	25	88
PSP	500	500	400	400	20	20	20	20	0.0005	0.0005	0.0005	0.0005	-	40	95
Batteries	673	387	387	309	6.73	3.87	3.87	3.09	0.0001	0.0001	0.0001	0.0001	-	14	98

Table 1: Techno-economic data by power plant's type from 2023 to 2070
Data: [10], [19], [18], [22], [30]

The annuity ($K_{t,r,i}$) is defined in Eq.17. This equation follows the methodology of [31] and represents the annualized cost of the total investment cost of a certain technology spread over its technical lifetime, taking into account a discount rate. A discount rate β of 4% is chosen, based on a review of the literature and reports, as explained in Appendix C.

$$K_{t,r,i} = \frac{\beta \cdot CAPEX_{t,r,i}}{1 - (1+\beta)^{-\Lambda_{r,i}}} \tag{17}$$

With β the discount rate, $CAPEX_{t,r,i}$ the CAPEX of year t, region r and technology i, and $\Lambda_{r,i}$, the life duration of technology i in region r.

3.2.2. Transmission Lines

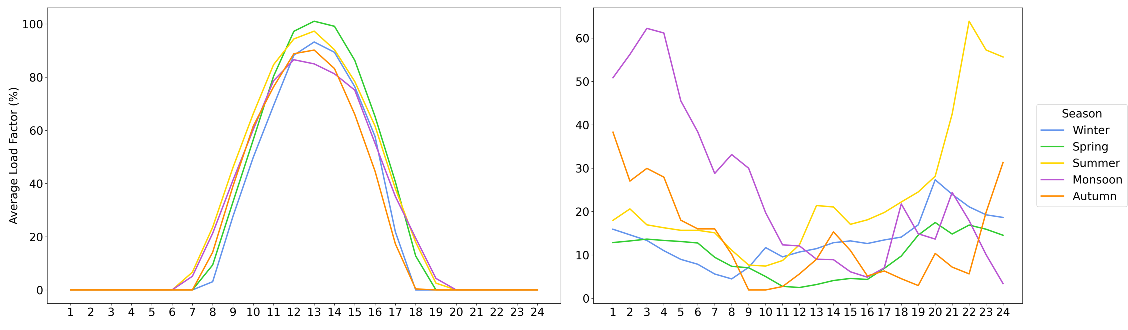
The seven inter-regional transmission lines are modeled as bidirectional links, enabling power exchanges to balance supply and demand between adjacent regions (Table 2). 2023 installed capacity data comes from the *National Electricity Plan Volume II* [32]. Investments in transmission capacity are endogenously determined by the model and are restricted to connections between neighboring regions. The distance between regions is approximated by the geographical distance (in km) between their respective economic centers [26]. Link costs represent the investment cost of constructing one kilometer of transmission line per megawatt of capacity and are sourced from [19]. Transmission costs denote the operational cost of transmitting one kilowatt-hour of electricity and are derived from India Transmission Portal website, while electricity prices reflect the trading cost per kilowatt-hour of electricity and are sourced from the Indian Energy Exchange market. The average electricity price for 2023 was chosen.

Inter-regional Transmission	Capacity in 2023 (GW)	Link Costs (₹/MW-km)	Transmission Cost (₹/kWh)	Electricity Price (₹/kWh)
North-West	37	10,163	5.7	4.965
North-East	23	10,163	5.7	4.965
North-NE	3	20,326	5.7	4.965
South-West	18	10,163	5.7	4.965
South-East	8	10,163	5.7	4.965
West-East	22	10,163	5.7	4.965
NE-East	3	20,326	5.7	4.965

Table 2: Total capacity of inter-regional transmission links and costs in 2023
Source: [19], India Transmission Portal, Indian Energy Exchange

3.2.3. Renewable Capacity Factor Profiles

When modeling variable energy sources, an important aspect to account for is the capacity factor, which enables an accurate representation of the electricity generation potential. The capacity factor of a plant indicates the ratio of actual electrical energy produced over a given period to the theoretical maximum output over a year (8,760 hours). It varies across regions due to factors such as weather conditions or technical constraints. In order to better capture the intermittency of variable renewable energy, we use regional and hourly capacity factors, sourced for [22]. Since the study by [22] provides capacity factor data only for 2040, we adjusted these factors by comparing the simulated generation based on the 2040 values with the actual generation in 2023 and scaled them accordingly. Figure 2 shows the average capacity factors that we derived for solar and wind by season in the Northern region for 2023. Capacity factors for intermittent renewables in other regions are provided in Appendix D.



(a) Average Solar Profile

(b) Average Wind Profile

Figure 2: Average Solar and Wind Profile per Season for Northern Region in 2023
Note:This figure presents the average hourly solar (left) and wind (right) load factors by season for the Northern Region. Solar load factors peak between 12:00 and 14:00 and are higher in spring and summer, whereas wind load factors tend to be higher at night, with patterns varying seasonally.
Data: [22], calibrated for accuracy

Finally, hydro capacity factors, that also come from [22], are calculated seasonally. Their average over the season is shown in Table 3. Since hydroelectric generation depends on water availability, the capacity factor of hydro plants is closely linked to rainfall patterns across different seasons depending on the region [33]. Therefore, capacity factors are modeled on a seasonal basis.

Load factor (%)	Winter	Spring	Summer	Autumn	Monsoon
Northern Region	24%	27%	49%	79%	32%
Southern Region	27%	31%	25%	28%	24%
Western Region	16%	23%	16%	33%	24%
Eastern Region	10%	11%	28%	50%	16%
North-Eastern Region	9%	7%	15%	32%	31%

Table 3: Capacity factors (%) for hydroelectricity plants per region and season in 2023
Data: [22] and calibrated for accuracy

3.2.4. Potential Installed Capacities and Deployment Rates

To ensure realistic deployment trajectories and account for the limited regional potential for each technology in India, maximum capacity thresholds have been defined. Table 4 summarizes the maximum potential capacities by technology and the corresponding sources. We assume that these maximum capacities will be reachable by 2050. To define the maximal deployment pathways by region until 2050, a constant growth rate, calculated between 2023 and 2050, has been applied to each technology. Notable exceptions are made for nuclear, coal, gas, and battery technologies. For nuclear power, two thresholds are considered: the first, in 2050, corresponds to the government's goal of reaching 100 GW of nuclear capacity by 2047 [34] while the second is extrapolated from the fourth Net-Zero scenario in [10], which emphasizes nuclear integration to achieve India's Net-Zero emissions target by 2070. Battery capacity thresholds are derived from the reference scenario of the NREL report [35], with no specific constraint by region. Regarding coal and gas technologies, the growth rate of installed capacities is unconstrained. Finally, we assume that both battery storage and carbon capture and storage technologies will be available in India by 2030.

Technology	Potential (GW)	Source
Hydro (> 25 MW)	142	[36]
Nuclear	178	[34], [10]
Solar	748	[37], [25]
Wind (150m)	1 163	[38], [25]
PSP	74	[39]
Biomass	42	[37]
Batteries	640	[35]

Table 4: Potential Installed Capacity by Technology in India (GW)

3.3. Electricity Demand

3.3.1. Extended demand

A key assumption in future power system modeling concerns the projected level of electricity demand. Variations in both total demand and peak load critically influence investment requirements [40]. For instance, in the context of grid decarbonization, if demand peaks do not align with the generation of variable renewable energy sources, substantial storage capacity may be required. Similarly, if high demand arises in regions with limited VRE potential, significant transmission infrastructure will be necessary. Therefore, modeling diverse demand levels is essential to capture the unpredictability associated with future electricity demand.

To represent those alternative development pathways, we use the forecasted demand projections from [26]. These data provide hourly electricity demand forecasts for each Indian region from 2020 to 2050, in five-year intervals, under three GDP growth scenarios: slow, stable, and rapid. The detailed methodology underlying these projections is presented in Appendix E.

Building on this work, we extend the forecasts to 2070. Given the high degree of unpredictability in projecting hourly demand over such an extended horizon, three distinct trajectories are constructed to reflect alternative growth pathways and peak load outcomes by 2070. To extend the stable scenario and represent a future where electricity demand grows linearly, electricity demand is extrapolated by calculating the average hourly variation between consecutive periods (e.g., 2025–2020, 2030–2025) and iteratively adding this average variation to the 2050 data to obtain demand levels up to 2070. To depict a future of accelerated demand growth toward 2070, the exponential function $y = \alpha^r + \beta^r exp(X)$ is applied, where the parameters α^r et β^r are estimated using average demand levels between 2020 and 2050. Finally, to represent a low-demand trajectory in which electricity use stabilizes or slightly declines after 2050, the slow scenario is extended by employing a logarithmic function, $y = \alpha^s + \beta^s log(X)$, where X denotes the year and y the average demand level. Figures illustrating the methodology are displayed in Appendix E and the evolution of demand levels and peak loads between 2030 and 2070 is summarized in Table 5.

Demand	**Variable**	**2030**	**2040**	**2050**	**2060**	**2070**
Slow	Demand (TWh)	1,858	2,258	2,501	2,453	2,527
	Peak (GW)	248	298	335	320	330
Medium	Demand (TWh)	1,960	2,587	3,238	3,867	4,495
	Peak (GW)	260	343	426	511	596
High	Demand (TWh)	2,058	2,923	3,982	5,950	8,631
	Peak (GW)	274	386	515	786	1,164

Table 5: Electricity demand and peak load projections (2030–2070)

3.3.2. Representative Weeks

As described in the above section, the model simulates India's electricity demand over the 2023–2070 period. To manage this extended time frame, ten representative weeks are selected to optimize hourly electricity generation while preserving the annual demand patterns. The year is divided into five seasons, Winter, Spring, Summer, Monsoon, and Autumn [19]. For each season, one representative week and the week containing the maximum demand are selected. Each representative week is then weighted according to the number of weeks in its corresponding season, ensuring a consistent approximation of the annual load profile. The detailed methodology for selecting the representative weeks is provided in Appendix F.

3.4. Definition of Scenarios

Four scenarios were defined to assess the optimal hourly dispatch and the technological investment choices across India's five regions: North, West, South, East, and Northeast. Investment outcomes are driven by the implementation of climate policies and by variations in electricity demand. For each scenario, we evaluate CO_2 emissions, the optimal electricity mix, and the associated investment trajectory.

For the sake of consistency, identical assumptions regarding the supply side of the electricity market are applied across all scenarios. Following [10], we assume that capital and fixed O&M costs for solar, wind, biomass, gas, coal with CCS, PSP and batteries technologies will decline in 2040 and 2050, while other costs (fuel, variable and transmission costs) remain constant. We also assume that batteries and coal generation with CCS will become available by 2030. Capacity factors are held constant through 2070, implying that no major technological breakthroughs are considered and that climate change is not assumed to affect generation patterns.

3.4.1. Reference Scenario

The reference scenario represents the future of India's power system in the absence of any environmental policy, allowing CO_2 emissions to occur unrestricted. Electricity demand is projected to grow at a steady rate (medium demand). The objective is to identify the least-cost[4] electricity mix without imposing any CO_2 constraints. This scenario provides baseline results for the electricity mix serving as a reference against which the outcomes of other scenarios can be compared.

[4] If no CO_2 externalities are not considered

3.4.2. Net-Zero Scenarios

In the remaining three scenarios, CO_2 emissions are constrained: electricity generation is required to be carbon-neutral by 2070, in line with India's COP26 commitments [7]. It is important to note that we do not impose any specific CO_2 reduction trajectory prior to 2070. To assess the impact of varying demand levels on the costs of achieving the decarbonization target, we construct three demand scenarios for our analysis: (i) a slow-growth scenario (NZ-low), (ii) a steady-growth scenario (NZ-med), and (iii) a high-demand scenario (NZ-high). Table 6 summarizes the different scenarios considered in the analysis based on the policy and demand levels they integrate.

		Climate Policy	
		Business-as-Usual	Net-Zero Emission
	Low		**NZ-low**
Electricity Demand	Medium	**Reference**	**NZ-med**
	High		**NZ-high**

Table 6: Overview of the four scenarios by demand level and climate policy

4. Results

4.1. The Reference Scenario

Under the reference scenario, which assumes no CO_2 emission constraints and a rising electricity demand, exceeding 4,000 TWh by 2070, renewable energy sources including hydro, account for more than two third of total installed capacity (67%) by 2070. This increase is driven primarily by the growth of wind power, which reaches 550 GW, and closely followed by solar power, representing 475 GW by 2070. Taken together with hydro, wind and solar power represent more than half of total generation (52%). Coal-fired capacity keep expanding however, to 338 GW by 2070. Despite this increase, coal's share in electricity generation declines from 73% in 2023 to 30% in 2070. Nuclear power represents 7% of installed capacity (113 GW) in 2070 but contributes 17% of total generation, making it the fourth-largest source. The evolution of the power sector under the reference scenario is shown in Figure 3.

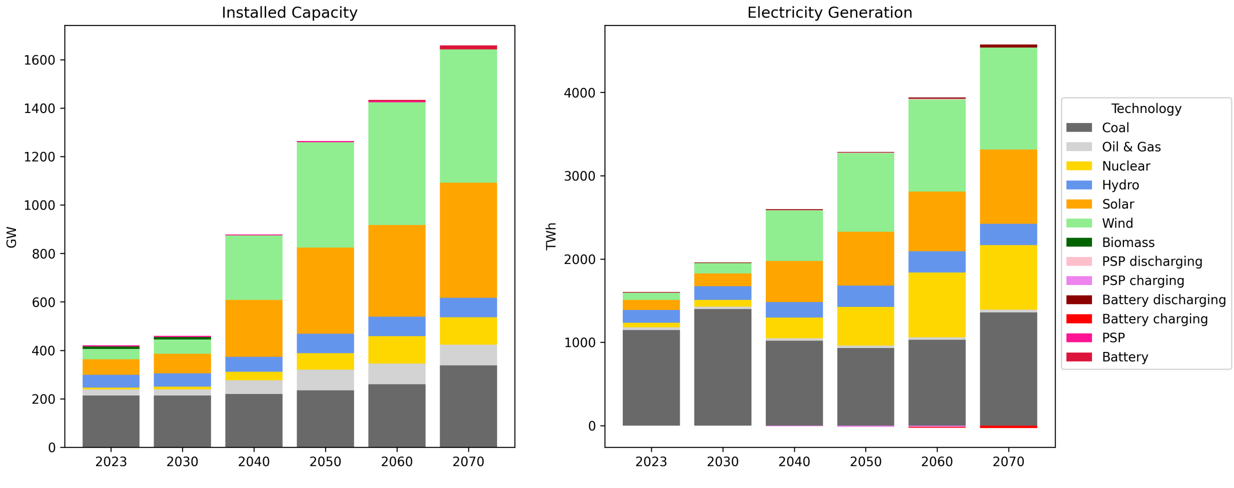


Figure 3: Evolution of installed capacities (left) and generation (right) by technology for the Reference scenario
Note: This figure depicts the evolution of installed capacities (GW, left panel) and electricity generation (TWh, right panel) by technology at the national level under the Reference scenario from 2023 to 2070. Negative generation values represent electricity used for energy storage to enable production.

The relatively modest expansion of hydro capacity and generation reflects the saturation of capacities in regions with the highest hydro capacity factors. A similar constraint applies to nuclear power, whose expansion is restricted by capacity saturation in the Northern and Western regions. For oil- and gas-fired power plants, growth in generation is constrained by the limited availability of domestic natural gas, which we assume to remain low. Given these limitations, wind and solar emerge as efficient and available options to meet rising electricity demand. Interestingly, in the Southern region, where renewable energy sources reach their highest penetration, with 553 GW installed by 2070, nuclear capacity is the lowest at just 6 GW and is largely replaced by coal. This outcome reflects our assumption that nuclear provides no balancing capability, whereas coal plants have higher ramping flexibility. Combined with hydropower, this flexibility helps compensate for the intermittency of renewables.

Regarding deployment dynamics, wind and solar capacity expand significantly, from 43 GW and 64 GW, respectively, in 2023 to 550 GW and 475 GW by 2070. This translates into average annual additions of about 10 GW for wind and 9 GW for solar. While the solar target appears realistic given current annual installations of roughly 12 GW (2022–2023) [4], [11], the required wind additions are far above the recent historical average of around 2 GW per year over the last decade [4]. Another major challenge concerns nuclear deployment, which would require building approximately 2 GW of capacity per year over 47 years.

It is important to note that the power sector does not achieve net-zero emissions in this scenario. CO_2 emissions continue to rise, from 1,222 $MtCO_2$ in 2023 to 1,435 MtC_2 in 2070, as illustrated in Figure 6.

4.2. The Net-Zero Scenarios

In the Net-Zero scenarios, CO_2 emissions are required to reach zero by 2070. Figures 4 and 5 illustrate the evolution of installed capacities and electricity generation for the low, medium, and high demand scenarios, with 2070 demand ranging from 2,527 TWh to 8,631 TWh.

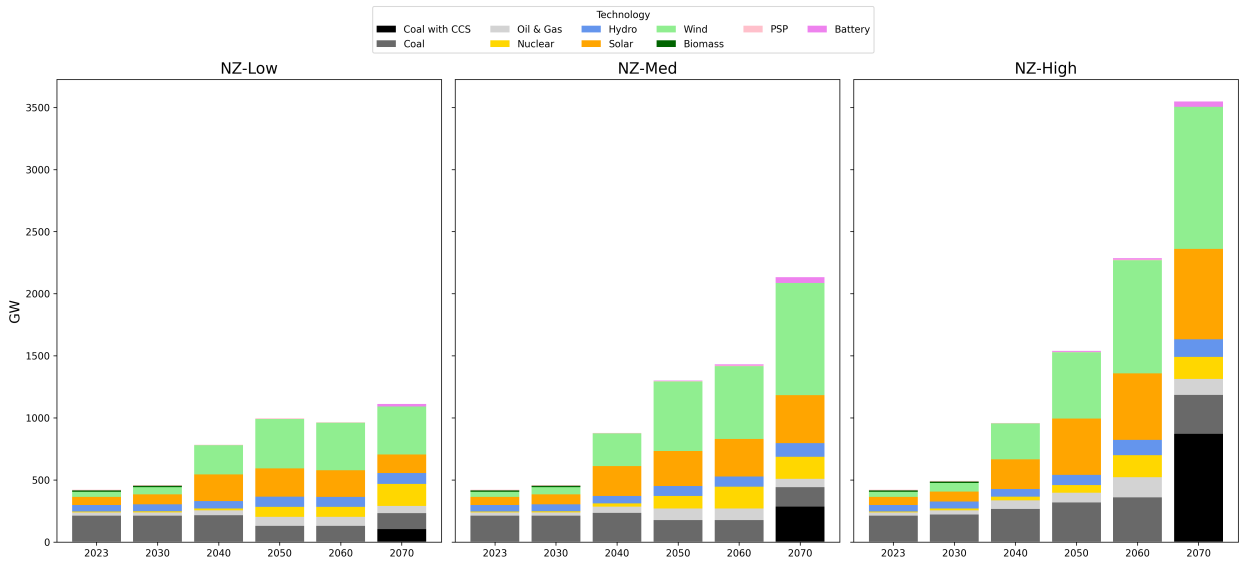


Figure 4: Evolution of installed capacities (GW) by technology for the Net-Zero scenarios
Note: This figure illustrates the evolution of national installed capacities by technology (GW) across all Net-Zero scenarios from 2023 to 2070.

In the low-demand scenario, electricity generation in 2070 is dominated by nuclear power, which accounts for 42% of the mix. Wind provides 30%, while hydro and solar each contribute around 11%, and coal with CCS supplies 6%. Although their share in the mix is relatively modest, nuclear and hydro operate at full capacity in 2070 (178 GW and 88 GW[5], respectively). Wind and solar capacity reach 387 GW and 149 GW, while 104 GW of coal with CCS is installed between 2060 and 2070, equivalent to an annual addition of 10 GW.

In the medium-demand scenario, electricity demand nearly doubles by 2070 compared to the low-demand case. As in the low-demand scenario, nuclear and hydro operate at full utilization, providing 24% and 6% of total generation.

[5]Hydro operates at full capacity in the Northern, Southern, and Western regions, and is only marginally used elsewhere.

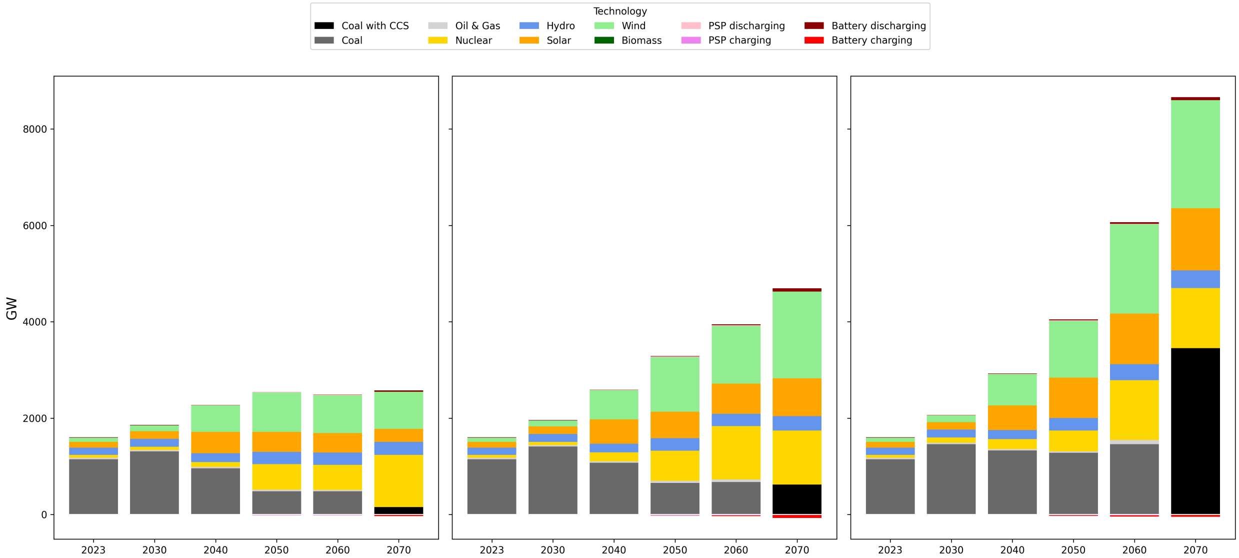


Figure 5: Evolution of generation (TWh) by technology for the Net-Zero scenarios
Note: The figure presents the evolution of electricity generation (TWh) by technology at the national level for all Net-Zero scenarios over the period 2023–2070.

The remainder is supplied by wind (38%), solar (17%), and CCS (13%). Installed capacity reaches 178 GW for nuclear, while wind and solar expand to 904 GW and 386 GW. Between 2060 and 2070, the results indicate additions of 286 GW of CCS, 317 GW of wind, and 82 GW of solar capacity.

In the high-demand scenario, total electricity demand exceeds 8,000 TWh by 2070. CCS becomes the dominant technology, supplying 40% of demand, as all other technologies reach their deployment limits. Hydro and nuclear reach full utilization by 2050. Wind provides 26% of generation, followed by solar (15%) and nuclear (14%). CCS capacity increases to 871 GW by 2070, while solar and wind reach 728 GW and 1,144 GW. This corresponds to annual additions (2060–2070) of 87 GW for CCS, 23 GW for wind, and 19 GW for solar. Those high deployment rates raise concerns about their practical feasibility.

Regarding CO_2 emissions (Figure 6), both the low- and medium-demand scenarios show a peak around 2030, followed by a two-stage decline: first as nuclear and hydro reach their maximum deployment levels by 2050, and later with the introduction of coal with CCS, which is essential for achieving net-zero emissions by 2070 in these scenarios. In the high-demand case, emissions remain between 1,400 and 1,600 Mt of CO_2 until 2060 before dropping sharply to zero by 2070. This trend arises because, despite large-scale deployment of renewables, coal plants continue to be built in the Southern and Eastern regions to meet demand. As a result, CO_2 intensity (CO_2/MWh) remains similar across all scenarios up to 2040: before 2050, most low-carbon technologies have not yet reached their maximum potential and remain the cheapest sources of generation. After 2040, emissions intensities in the Reference and NZ-high scenarios continue to decline but at a slower pace, reflecting the need for thermal capacity to balance intermittent renewables and satisfy rising demand. Ultimately, coal with CCS is required in all scenarios to close the remaining gap and achieve net-zero CO_2 emissions by 2070. Finally, it is worth noting that the NZ-low and NZ-medium scenarios exhibit very similar decarbonization trajectories. This similarity is driven by comparable demand levels through 2050 and by nearly identical generation mixes in percentage terms, with thermal generation still representing around 25% in 2050. This highlights the persistent need to retain a minimum share of dispatchable thermal technologies to balance intermittent renewable generation in both scenarios.

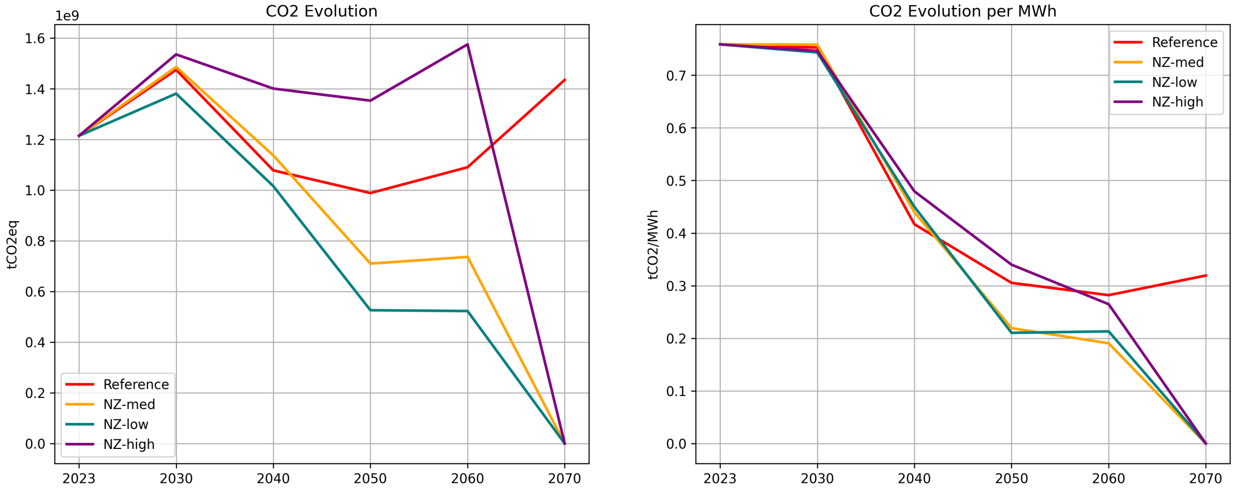


Figure 6: CO_2 emission evolution in tonnes of CO2 (left) and per MWh (right) for each scenario
Note: This figure illustrates the evolution of CO_2 emissions by scenario from 2023 to 2070, expressed in tonnes of CO_2 equivalent (left) and in tonnes of CO_2 per MWh (right).

5. Discussion

Some observations regarding the three scenarios are noteworthy. First, regardless of the scenario, stranded thermal assets (coal and oil & gas capacities) remain in 2070. In this framework, it is economically optimal to continue investing in thermal capacities until 2060 to meet electricity demand and then bear the fixed costs these plants, rather than retiring them earlier to decarbonize, resulting in 127–360 GW of stranded assets across scenarios. Second, the model consistently relies on CCS technology, which is not yet mature at large scale, raising questions about the feasibility of fully decarbonizing the Indian power system, particularly under high-demand conditions. Relatedly, battery usage remains low, representing only 2–3% of installed capacity and less than 1% of generation across scenarios. This can be explained by the fact that we used a linear model, where storage demand is underestimated compared to MILP [29], but is also reflected by the high cost of batteries, with the model relying primarily on hydro and then on coal with CCS as backup technologies. Moreover, as mentioned earlier, in the low- and medium-demand scenarios, hydro potential remains untapped in the Northeastern region, while the Southern region relies on coal to balance its intermittent generation. Reducing transmission costs could facilitate greater electricity exchanges between regions, enabling balancing of supply and demand and allowing wider deployment of cost-effective renewable electricity. Finally, decarbonization of the power system occurs predominantly in the last decade before 2070. This implies that, without either a CO_2 price or a decarbonization pathway from public authorities, annual CO_2 emissions would remain above 1 $GtCO_2$ up until 2060.

6. Conclusion and Further Research

This article studies the optimal decarbonized electricity mix for the Indian power sector by 2070. To this end, a bottom-up linear dynamic optimization model that accounts for inter-regional power transmission and captures both diurnal and inter-seasonal variability of renewable energy source has been developed. It includes three renewable technologies, thermal plants, nuclear power, storage technologies, as well coal with carbon capture and storage. Four scenarios have been built to assess a wide range of future demand level for India, under the hypothesis of declining costs for renewable technologies, batteries and coal with CCS.

Findings shows that although renewables dominate capacity growth, dispatchable thermal technologies remain essential to ensure system flexibility and reliability. Across all scenarios, wind and solar account for the majority of installed capacity growth by 2070, driven by rising electricity demand and constraints on hydro and nuclear expansion. However, their intermittency and regional saturation effects imply a continued need for dispatchable thermal capacity.

Coal (in the reference case) and coal with CCS (in Net-Zero scenarios) play a critical balancing role, particularly in regions with high renewable penetration and limited nuclear flexibility.

Moreover, achieving net-zero emissions requires large-scale deployment of nuclear, hydro, and coal with CCS. In the Net-Zero scenarios, nuclear and hydro reach full utilization by mid-century and form the backbone of early decarbonization. Nevertheless, they are insufficient on their own to meet demand growth, especially in medium- and high-demand cases. CCS becomes indispensable after 2050 and ultimately supplies a substantial share of generation, especially under high demand, making it a key technology for closing the emissions gap and achieving net-zero by 2070.

Finally, deployment feasibility is a major constraint, especially under the high demand scenario. The required build rates for wind, solar, nuclear, and CCS, particularly in the medium- and high-demand Net-Zero scenarios, far exceed historical deployment levels. While solar expansion appears broadly realistic, wind, nuclear, and coal with CCS face significant feasibility challenges due to the scale and speed of investment needed. Such deployment rates raise questions about the feasibility of reaching carbon neutrality by 2070 under a high electricity demand trajectory. This challenge could be mitigated through efficiency measures, such as improving household appliances like air conditioners, or by reducing transmission and distribution losses, which currently account for nearly 18% of total available electricity [4].

This work could be extended along several dimensions. First, a min–max regret analysis could be conducted to evaluate the importance of accurate capacity sizing relative to under- or over-investment in power infrastructure, under uncertainty about future electricity demand [41]. Second, while the present study assumes no change in climate and therefore does not capture climate-related impacts on demand or supply patterns, a deeper assessment of long-term power capacity expansion would require explicitly accounting for climate change. This could be achieved by modeling evolving electricity demand patterns and incorporating changes in electricity generation, for example through altered hydropower availability or cooling constraints for thermal power plants.

Appendix A. Electricity Demand Review

Source	Scenario	2040	2050	2060	2070
[25]			6,273 TWh		
[11]	Business-as-usual				7,900 TWh
	High-electrification				12,800 TWh
[26]			4,199 to 4,773 TWh		
[21]		4,500 TWh			
[24]		4,891 TWh	6,977 TWh	9,309 TWh	
	Low		3,406 TWh		3,070 TWh
[10]	Medium		4,176 TWh		4,070 TWh
	High		4,678 TWh		5,026 TWh
[22]			3,500 to 4,000 TWh		
[42]			9,000 TWh		

Table A.7: Summary of literature's long-term electricity demand projections

Appendix B. Fuel Costs and Parameters

Table B.8 shows the thermal efficiency of each type of fuel used in power plants in 2023. Efficiency parameters, representing the amount of MWh generated per MMBtu of each fuel, are sourced from [22].

Fuel types	Uranium	Domestic Coal	Imported Coal	Domestic Gas	Imported Gas	Biomass
Thermal Efficiency (MWh/MMBtu)	0,099	0,11	0,13	0,15	0,17	0,06

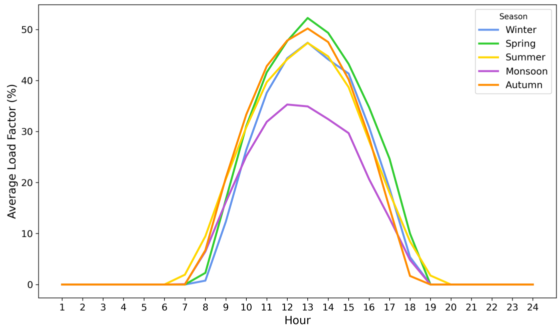
Table B.8: Fuel thermal efficiency per fuel type in 2022
Data: [24], [22]

Appendix C. Choice of the Discount Rate

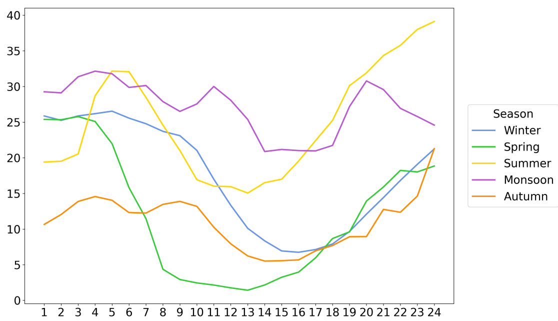
The discount rate, expressed in real terms, of 4% used in this study is based on both academic literature and official reports. Existing research on the decarbonization of India's power system shows considerable heterogeneity in discount rate assumptions, when they are reported at all. To the best of our knowledge, several studies do not specify any discount rate ([26], [25], [22]). Among those that do, the values range widely, from 4% [24] to 9–10% ([11], [21]), and it is often unclear whether these rates are expressed in real or nominal terms. To better inform our choice, we examined reports from Indian institutions. The appraisal guidelines from [43] recommend a discount rate of 4% and 8%, depending on the project duration. A note from the Central Electricity Regulatory Commission [44], focusing specifically on transmission investments, applies a nominal rate of 9.88% ($\beta_{norminal}$ = 9.88%) and reports inflation at 4.94% (π = 4.94%). Using the Fisher equation (Eq. C.1), this implies a real discount rate of approximately 4.71% (β_{real} = 4.71%). In addition, a working paper by the National Bank for Agriculture and Rural Development [45] estimates a social discount rate of 3.72%. Considering the range of values found in the literature and the guidance from Indian governmental reports, we adopt a real social discount rate of 4% for this study. We assume that this rate remains constant over the horizon to 2070.

$$1 + \beta_{\text{real}} = \frac{1 + \beta_{\text{nominal}}}{1 + \pi} \tag{C.1}$$

Appendix D. Regions' Renewable Capacity Factors

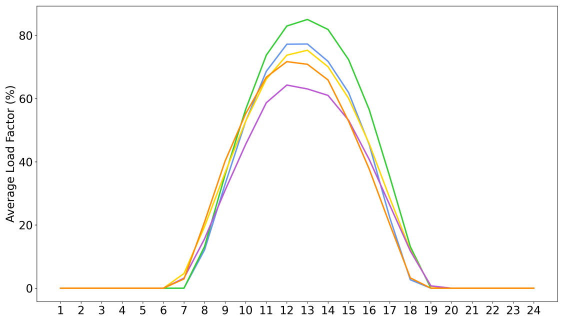


(a) Average Solar Profile

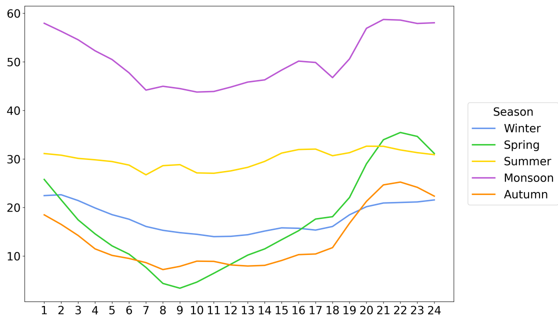


(b) Average Wind Profile

Figure D.7: Average Solar and Wind Profiles per Season for Western Region in 2023
Note: This figure shows the average hourly solar (left) and wind (right) load factors by season for the Western Region. Solar load factors peak between 11:00 and 13:00 and are highest during spring and the monsoon season, whereas wind load factors tend to be higher at night, with patterns varying across seasons.
Data: [22], calibrated for accuracy



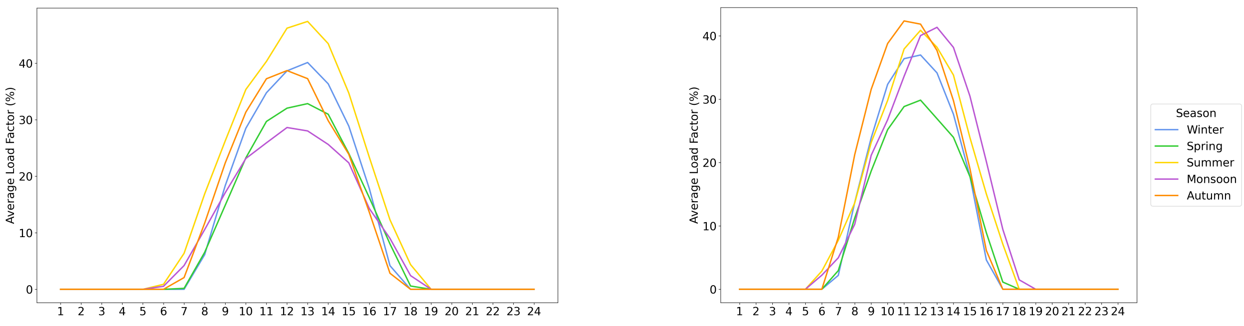
(a) Average Solar Profile



(b) Average Wind Profile

Figure D.8: Average Solar and Wind Profiles per Season for Southern Region in 2023
Note: This figure presents the average hourly solar (left) and wind (right) load factors by season for the Southern Region. Solar load factors peak between 11:00 and 14:00 and are higher in spring and winter, whereas wind load factors are slightly higher at night, with levels varying considerably across seasons.
Data: [22], calibrated for accuracy

Because no wind power plants are installed in the Eastern and Northern regions, only solar capacity factors are displayed.



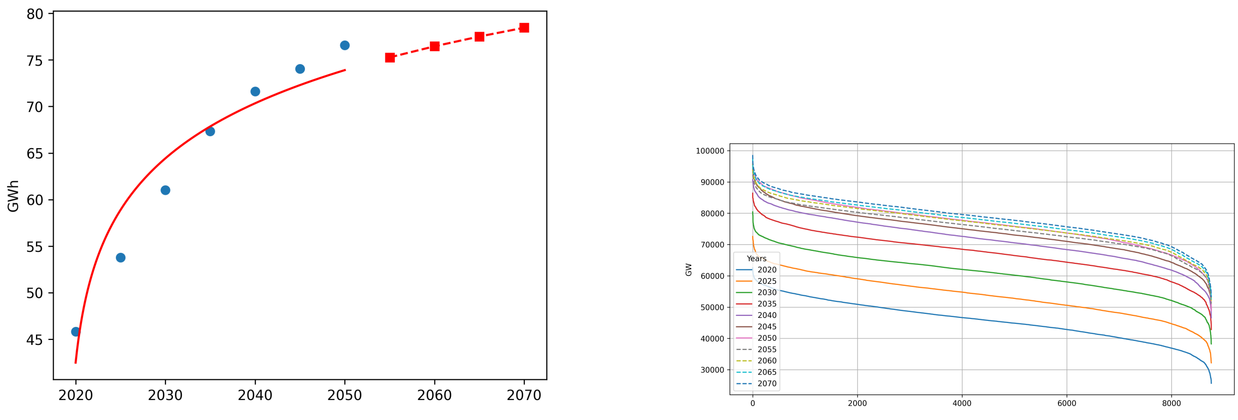
(a) Average Eastern Solar Profile

(b) Average North-Eastern Solar Profile

Figure D.9: Average Solar Profiles per Season for Eastern and North-Eastern Regions in 2023
Note: This figure illustrates the average hourly solar load factor by season for the Eastern and Northeastern regions. In the Eastern region, solar load factors peak between 11:00 and 14:00 and are highest during spring and winter, whereas in the Northeastern region, autumn and the monsoon season exhibit the highest load factors.
Data: [22], calibrated for accuracy

Appendix E. Electricity Demand Forecast

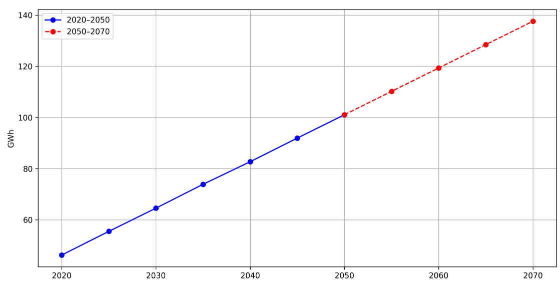
Our model uses electricity demand forecast coming from the study of [15]. Figures E.10 to E.12 illustrate how electricity demand was extended to 2060 and 2070 for the Northern region. The left panels show the extrapolated average electricity demand for the low, medium, and high datasets using the three models described in the article. The right panels present the extended hourly load curves obtained by applying each model to the corresponding hourly data.



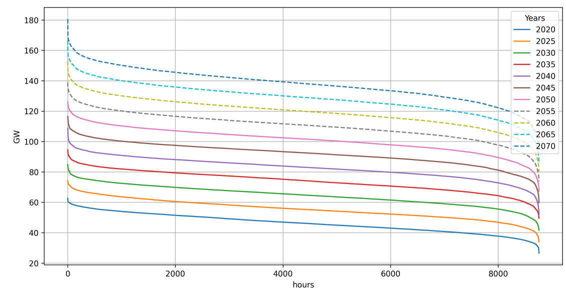
(a) Average and extended demand

(b) Load curves from 2023 to 2070

Figure E.10: Average Demand and Load curves for the Northern Region - Low Scenario
Note: The left panel shows the average annual demand (GWh) for the Northern Region in blue. The solid red lines indicate the fitted values from the logarithmic regression, and the red dots represent the projected demand levels for 2055–2070 using the log function. The right panel displays the annual load curves for the Northern Region from 2023 to 2050 (solid lines), while the dashed lines show the extended load curves for 2055–2070.

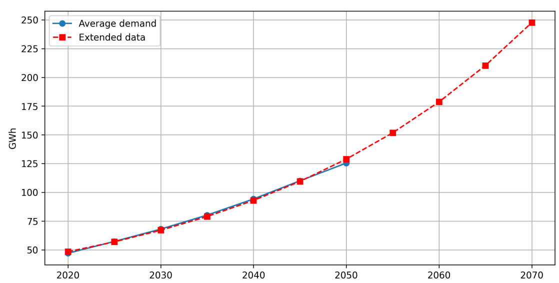


(a) Average and extended demand

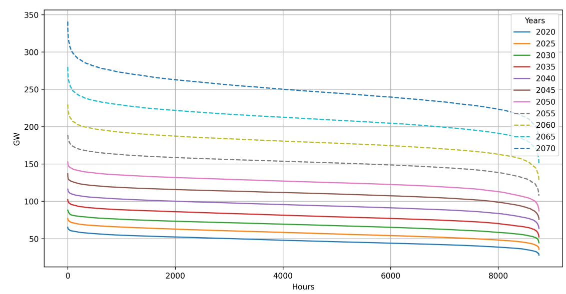


(b) Load curves from 2023 to 2070

Figure E.11: Average Demand and Load curves for the Northern Region - Medium Scenario
Note: The left panel displays the average annual demand (GWh) for the Northern Region in blue, with red dots representing the projected demand for 2055–2070. The right panel displays the annual load curves for 2023–2050 (solid lines), while the dashed lines indicate the extended load curves for 2055–2070.



(a) Average and extended demand



(b) Load curves from 2023 to 2070

Figure E.12: Average Demand and Load curves for the Northern Region - High Scenario
Note: The left panel shows the average annual demand (GWh) for the Northern Region in blue. Solid red lines indicate the fitted values from the exponential regression, while red dots represent the projected demand for 2055–2070. The right panel displays annual load curves for 2023–2050 (solid lines), with dashed lines showing the extended load curves for 2055–2070.

Appendix F. Demand

Due to the limited ability to store electricity, production must be adjusted in real time to match demand, even during periods of extreme consumption (peak of electricity demand). Accurately representing future load curves for each region, which reflects variations in electricity demand over time, is crucial for capturing the specific features of the Indian power system.

Appendix F.0.1. Representative Weeks

Two methodologies are commonly used in the literature to represent the load curve. Some studies, particularly those focused on integrating VRE into the energy mix, use hourly optimization, where the model calculates the optimal energy mix for each hour ([22], [24], [46]). Alternatively, time slices are used to approximate seasonal and diurnal load patterns while preserving computational efficiency. [20].

Our model covers India's electricity demand from 2023 to 2070. To simplify this extensive period, we select ten representative weeks to optimize hourly electricity generation while preserving the annual demand patterns. This approach enables us to account for the intermittency of VRE. Five of these weeks correspond to the representative weeks of the five seasons Winter, Spring, Summer, Monsoon, and Autumn. The remaining five weeks represent the periods of maximum demand throughout the year. Each representative week is weighted according to the number of weeks in its respective season, providing a robust approximation of the annual load while maintaining essential detail.

To define the five electricity demand periods for each region, we first divide the year into five groups, aligning with the seasons (Figure F.13).

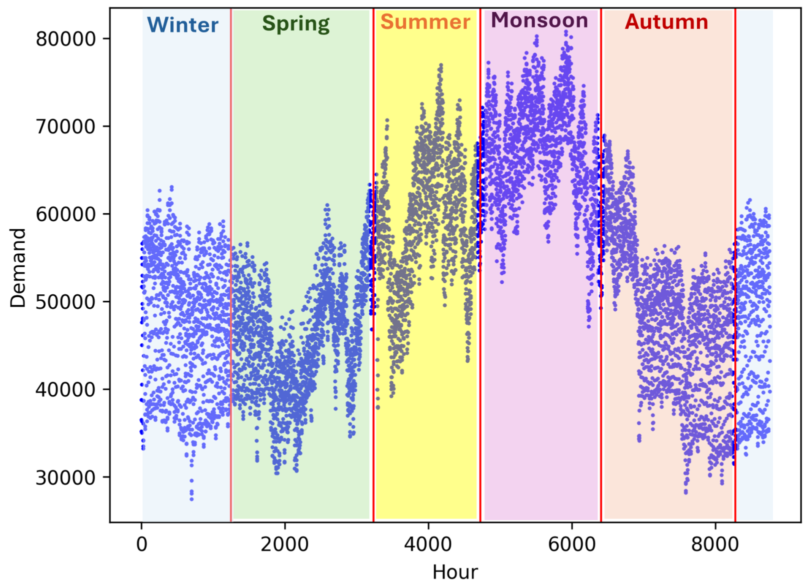


Figure F.13: 2023 Northern Region's Load curve and Season Clustering (MW)
Note: This figure shows the Northern Region load curve for 2023, with each dot representing hourly demand in MW. The year is divided into five seasons, each indicated by a different color.
Source: Authors' figure - Data: India Climate and Energy Dashboard

The second step involves selecting a representative week for each season. To achieve this, the average p-norm of each week is calculated within a season to all other weeks (Eq. F.1) and leads to the selection of the week with the minimum average distance (Eq. F.2). After conducting tests for different p-values, we choose the Euclidean norm (p = 2), as it ensures a good fit between the representative load curve and the actual one. Additionally, five weeks of maximum demand are selected, those in which the highest electricity demand of the season occurs, to capture extreme electricity demand in each region. Figure F.14 represents the North' load demand during the Monsoon season, with the selected representative week highlighted in red.

Representative Week ($RepWeek_{r,s}$).

$$DistWeek_{r,s}^{i,j} = \left(\sum_{h=1}^{168} (demand_{r,s,h}^{j} - demand_{r,s,h}^{i})^{p} \right)^{\frac{1}{p}} \tag{F.1}$$

$$RepWeek_{r,s} = min \sum_{j=1}^{nbweek_{r,s}} \frac{DistWeek_{r,s}^{i,j}}{nbweeks_{r,s}} \tag{F.2}$$

With $DistWeek_{r,s}^{i,j}$ the p-norm that represents the distance between weeks i and j of region r and in season s. $demand_{r,s,h}^{j}$ represents the electricity demand of region r, season s hour h and week j. $RepWeek_{r,s}$ is the representative week of region r and season s selected as the week with the minimum average distance compared to the other weeks from the same season. Finally, $nbweek_{r,s}$ corresponds to the number of weeks in season s for region r.

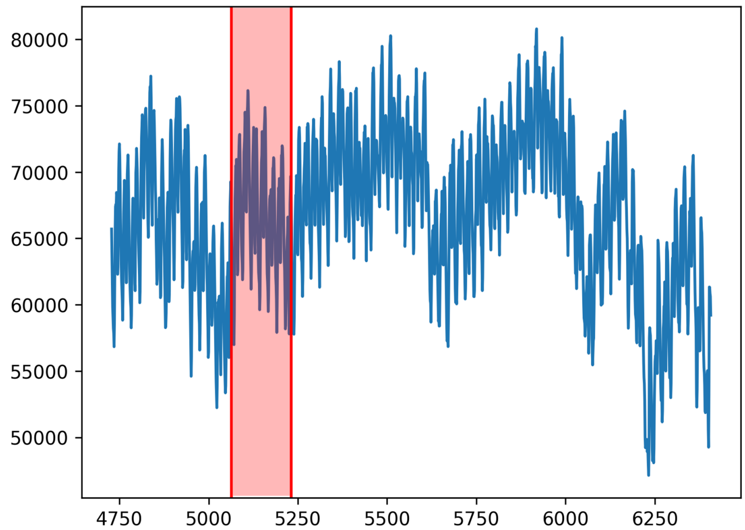


Figure F.14: Northern Region's Representative Week of the Monsoon season in 2023 (MW)
Note: This figure presents the hourly demand (MW) for the Monsoon season in the Northern Region in 2023, with the representative week highlighted in red.
Source: Authors' figure
Data: India Climate and Energy Dashboard

We obtain ten representative weeks, each consisting of 168 hours weighted according to the number of weeks it represents, to approximate the yearly load curves. Figure F.15 compares the actual (blue) and simulated (red) annual load curves for the Northern region in 2023. The simulated curve closely follows the actual one, accurately capturing peak demand but slightly overestimating low-demand periods. The mean absolute percentage error (MAPE) was calculated for each region, ranging from 2.7% in the Northern region to 1.2% in the Northeastern region.

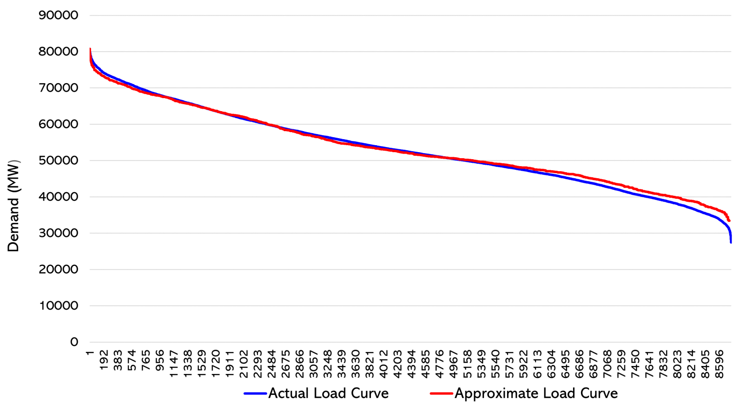


Figure F.15: Northern Region's Simulated (red) and Real Load (blue) Curves (MW)
Note: This figure compares the actual (blue) and simulated (red) load curves for the Northern Region in 2023. The simulated load curve is obtained by weighting each representative week according to the number of weeks it represents.
Source: Authors' figure
Data: India Climate and Energy Dashboard

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