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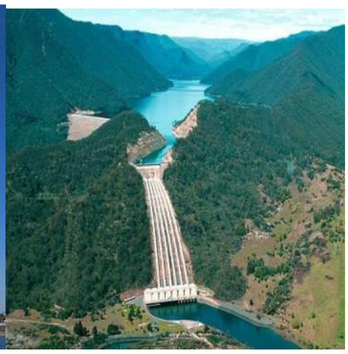
Draft Discussion Paper
On Methodology for
Capacity Credit of Generation Resources
&
Coincident Peak Requirement of Utilities
under
Resource Adequacy Framework



Government of India
Ministry of Power
Central Electricity Authority

Executive Summary

Since 2014, India has significantly transformed its energy sector, moving from coal-based power generation to a greater reliance on renewable energy sources. The Indian government has introduced ambitious initiatives like the National Solar Mission and the Green Energy Corridor Project to boost renewable energy adoption and improve grid infrastructure. This shift from coal to a renewable energy-dominated landscape represents a crucial step towards sustainable development and energy independence. The transition to renewable energy has its own challenges and potential benefits, and its impact on energy security, sustainability, and economic growth needs to be assessed. Significant investments were made in solar and wind energy projects, leading to substantial growth in renewable energy capacity. Solar capacity alone has increased from 2.63 GW in 2014 to over 81 GW by 2023. India has set an ambitious target of achieving 50% of installed capacity from non-fossil sources by 2030 as part of its NDC commitment.

However, integrating renewable energy sources such as solar, wind, and other renewables into the grid presents unique challenges and opportunities. Due to the variability and intermittency associated with these sources, the challenges of grid safety and the supply of reliable power to end consumers persist.

One critical aspect of this integration is understanding and utilizing the capacity credit of these sources. Capacity credit refers to the dependable capacity of a power source to contribute reliably to the electricity grid. Unlike traditional fossil fuel-based power plants, renewable energy sources have variable outputs influenced by weather conditions and time of day. System planner must use a scientific approach to determine the capacity credit for VRE sources to accurately determine the firm power available from these sources and optimize their energy portfolio accordingly. This will also help in accelerating the VRE addition plan for utilities to meet their future energy demand.

As per the Resource Adequacy Guidelines. Central Electricity Authority is mandated to calculate the capacity credit of various sources and provide the same to state utilities. CEA is also mandated to determine the coincident peak contribution of different states and utilities during the National Peak. Distribution utilities are also mandated to determine the capacity credit of their resources using a scientific methodology. As per the guidelines the coincident peak needs to be published for the next two years and needs to be updated annually.

This paper examines various methods for assessing the capacity credit of solar, wind, and other renewable energy sources. It discusses the importance of capacity credit for grid stability and energy planning. Additionally, this paper serves as a guide for utilities to calculate capacity credit for their specific resources and to determine their coincident peak requirements during National Peak.

Incorporating the capacity credit of variable renewable energy (VRE) into energy planning processes improves the predictability, reliability, and sustainability of the energy system. It enables stakeholders to make informed decisions that optimize resource utilization, support grid stability, and accelerate the transition to a low-carbon energy future.

Contents

1.0 Introduction

The global transition towards green energy is gaining momentum as countries worldwide commit to reducing carbon emissions and mitigating climate change impacts. This transition encompasses a shift from fossil fuel-based energy sources to renewable energy alternatives such as solar, wind, hydro, and geothermal. Governments, businesses, and communities increasingly invest in renewable energy infrastructure, incentivize clean technology adoption, and implement policies to promote sustainability. Countries are setting ambitious targets for renewable energy deployment, with many committing to achieving net-zero emissions by mid-century or earlier (USA by 2050, China By 2060, and INDIA by 2070). This commitment is driving investments in renewable energy technologies, energy efficiency measures, and grid modernization efforts to support the integration of variable renewable sources like solar and wind power.

India's power sector has seen a huge transition during the last few years shifting from a Fossil-rich to RE dominant resource mix. In August 2022, India updated its NDC according to which target to reduce the emissions intensity of its GDP has been enhanced to 45 percent by 2030 from the 2005 level, and the target on cumulative electric power installed capacity from non-fossil fuel-based energy resources has been enhanced to 50% by 2030. Consecutively, there has been a substantial addition of renewable energy and transmission capacities.

While Variable Renewable Energy (VRE) sources such as solar and wind power offer significant environmental benefits and are essential for reducing carbon emissions, they also present several challenges that need to be addressed for their widespread adoption and integration into the energy system which include:

- **Integrating Intermittency**: Solar and wind power generation fluctuates with weather conditions and time of day, leading to intermittency in energy supply. This variability can pose challenges to grid stability and reliability, requiring advanced forecasting, grid management, and energy storage solutions to balance supply and demand effectively.
- **Grid Integration**: Integrating high levels of VRE into existing grids can strain grid infrastructure designed primarily for dispatchable power sources. Challenges include grid congestion, voltage fluctuations, and the need for enhanced transmission and distribution infrastructure to accommodate decentralized renewable energy generation.
- **System Flexibility**: Unlike traditional power plants, VRE sources cannot be dispatched on demand. This lack of dispatchability necessitates flexible grid management strategies, such as demand response, energy storage, and flexible generation sources, to maintain grid stability and meet varying electricity demand.
- **Cost and Economics**: While the cost of solar and wind energy has decreased significantly over the years, there are still economic challenges associated with VRE deployment. These include upfront capital costs for infrastructure, intermittency-related costs (e.g., backup generation or energy storage), and the need for supportive policies and incentives to drive investment in renewable energy projects.
- **Location-Specific Resource Availability**: The availability and intensity of solar and wind resources vary geographically, leading to location-specific challenges in maximizing energy yield and integrating renewable energy into regional grids. Remote and off-grid areas may face additional logistical and economic barriers to deploying VRE technologies effectively.

- **Environmental and Social Impacts**: While VRE sources have lower environmental impacts compared to fossil fuels, they can still pose environmental challenges such as land use impacts, habitat disruption, and potential conflicts with local communities over land rights and resource use. Balancing environmental sustainability with social acceptance is crucial for the long-term success of renewable energy projects.

2.0 Resource Adequacy Guidelines Framework

DISCOMs are required to provide their consumers with a reliable, round-the-clock power supply. They must secure adequate capacity to meet consumer demand and, in accordance with the Nationally Determined Contributions (NDC) targets, fulfill their Renewable Purchase Obligation (RPO).

In this context, Resource Adequacy studies become crucial. Resource Adequacy involves ensuring that sufficient capacity is available to meet the expected demand of consumers within a DISCOM's service area in a cost-effective manner across all periods. These studies will determine the amount and type of generation resources needed in a distribution licensee's portfolio to optimally (i.e., with minimal cost and maximum security) meet future demand. This approach is essential for maintaining a reliable power supply for end consumers.

Under Rule 16 of Electricity (Amendment) Rules, 2022, the Ministry of Power, Government of India, in consultation with the Central Electricity Authority (CEA), issued the guidelines for Resource Adequacy for the Indian electricity sector in June 2023.

The relevant provisions of the Resource Adequacy Guidelines are mentioned below:

1. The Central Electricity Authority is mandated to publish a Long-term National Resource Adequacy Plan (LT-NRAP) which shall determine the optimal Planning Reserve Margin (PRM) requirement at the All-India level conforming to the reliable supply targets. The report shall publish the national-level PRM as a guide for all the States/UTs to consider while undertaking their RA exercises. (section 3.1)
2. The report shall also publish the capacity credits for different resource types on a regional basis. (Section 3.1)
3. The report shall specify the State/UT's contribution towards the national peak. (Section 3.1)
4. Each Distribution licensee shall undertake a Resource Adequacy Plan (RAP) for a 10-year horizon (Long-term Distribution Licensee Resource Adequacy Plan (LT-DRAP)) to meet their peak and electrical energy requirement. (Section 3.7)
5. The distribution licensees shall refer to LT-NRAP if required for inputs like PRM, capacity credits, etc. while formulating their LT-DRAP and submitting their plans to CEA. (Section 3.7.1)

The Guidelines also mention methodology for the determination of Capacity credit for various energy Sources (Annexure C of Resource adequacy guidelines). Three different methodologies suggested in the guidelines are mentioned below.

1. Capacity Credit during Top Demand Hours (Gross Demand)
2. Capacity Credit during Top Demand Hours (Netload Demand Curve)

3. Capacity Credit using ELCC (Effective Load Carrying Capacity)

2.1 Mathematical Modelling for Resource Adequacy

The Use of Scientific model to determine the optimal energy mix has evolved significantly over the past decades, driven by advances in technology, increased computational power, and the growing complexity of energy systems. Here are some key trends and developments in this area:

- **Integration of Renewable Energy**: Models have become essential for integrating variable renewable energy sources like solar and wind into the energy mix. Advanced simulation tools and modelling techniques enable the assessment of renewable energy penetration levels that maximize system reliability while minimizing costs and environmental impacts.
- **Economic Viability and Cost Optimization**: There is a strong emphasis on using models to optimize the economic viability of energy investments. Models assess the levelized cost of electricity (LCOE) across different technologies, considering capital costs, fuel prices, operating expenses, and financing options to identify the most cost-effective mix of generation resources.
- **Flexibility and Resilience**: Models are increasingly used to evaluate the flexibility and resilience of energy systems. This includes assessing the role of flexible generation technologies, energy storage, demand response, and grid infrastructure upgrades in maintaining grid stability and reliability amidst fluctuating demand and variable renewable energy output.
- **Environmental and Climate Considerations**: The integration of climate and environmental considerations into energy planning has led to the development of models that quantify the environmental impacts of different energy scenarios. Models assess greenhouse gas emissions, air quality impacts, water use, and land use to support decision-making aligned with climate goals and sustainability objectives.
- **Scenario Analysis and Uncertainty Management**: There is a growing emphasis on scenario analysis and uncertainty management in energy modelling. Models simulate multiple scenarios under varying assumptions (e.g., policy changes, technological advancements, economic conditions) to assess the robustness of different energy pathways and identify resilient strategies that can adapt to uncertain future conditions.

3.0 Coincident Peak

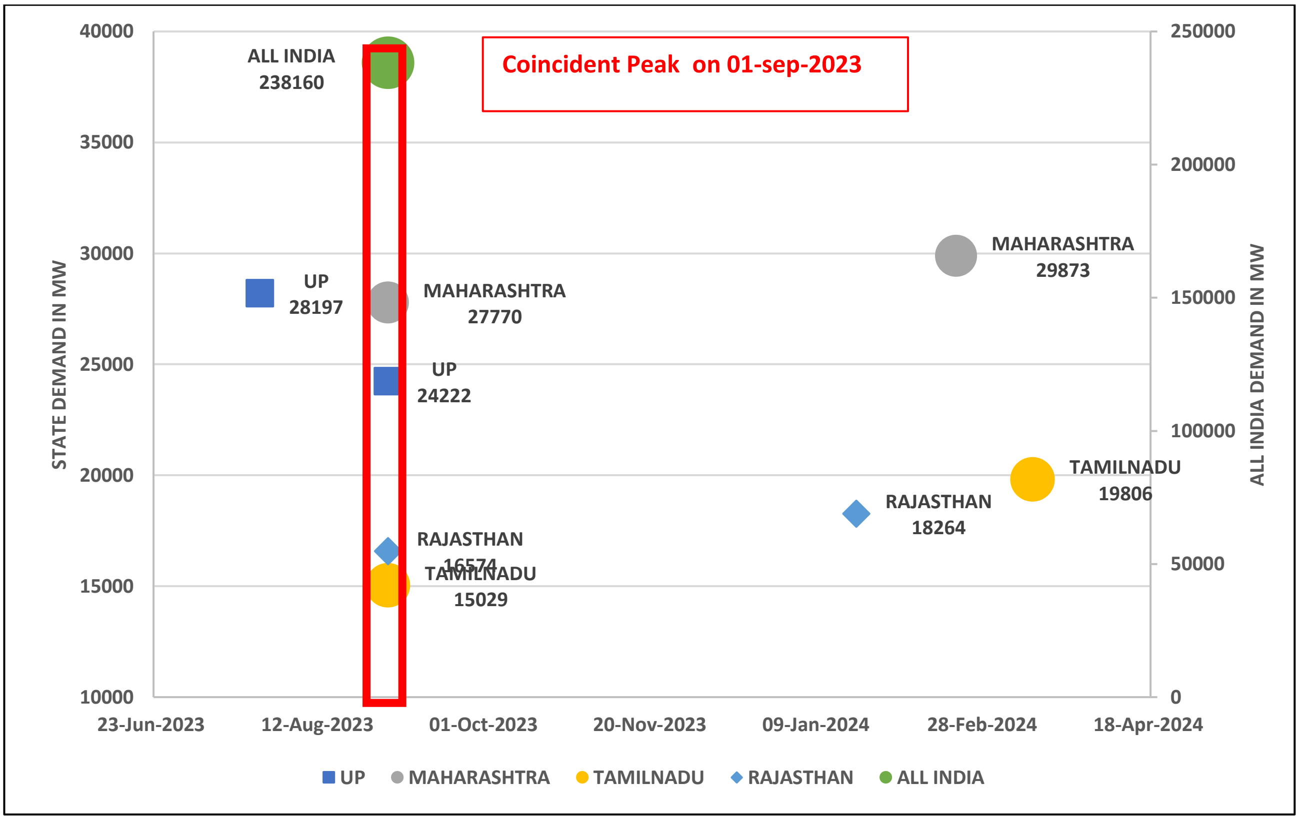
The term Coincident Peak refers to the share of different distribution utilities during the National Peak. Based on the previous year's demand profile, it has been observed that the occurrence of peak demand varies across months and times of day. Therefore instead of a single peak, the top 5%, or 10% of Demand hours of the national load should be considered for the determination of the coincident peak. The coincident peak may or may not coincide with the peak demand of respective utilities.

As per the Resource Adequacy Guidelines.

1. Based on the share in national peak provided in LT-NRAP, each distribution licensee shall plan to contract the capacities equivalent to (peak contribution * (1 + National level PRM)) as prescribed by LT-NRAP or higher to meet their Resource Adequacy Requirement (RAR) at the time of national peak. The distribution licensees shall demonstrate to the SERC/JERC a 100% tie-up for the first year and a minimum 90% tie-up for the second year to meet the requirement of their contribution towards meeting the national peak. Only resources with long/medium/short-term contracts shall be considered to contribute to the RAR. (Section 3.6)
2. Distribution licensees, through the LT-DRAP, shall also demonstrate to the SERC/JERC, their plan to meet their own Peak demand and energy requirement with a mix of long-term, medium-term, and short-term contracts, including power exchanges (Section 3.8).

During the National Peak Demand, the utilities must ensure adequate tied-up capacity from long-term, medium-term, and short-term (Bilateral only) as per their contribution to National Peak Demand +PRM (PRM value as determined by CEA).

Figure 1: Coincident Peak Vs Own Peak



The concept of the coincident peak can be explained through the above chart which shows the coincident peak and own peak of 4 of the major states (Uttar Pradesh, Maharashtra, Rajasthan, and Tamil Nadu) in terms of demand.

It can be observed that

- **Individual State Peaks Exceed National Share:** States often have higher peak electricity demand than their share during national peak hours.
- **State Demand Variation:** State peak demands are spread throughout the year, influenced by factors like diversity in consumption patterns.
- **Overcapacity Risk:** If states add new capacity based solely on their individual peak demands, it could lead to excess capacity addition and underutilization. For example, Uttar Pradesh's peak demand in 2023-24 was 28,197 MW, but its share during the national peak was only 24,222 MW.

3.1 Single Peak Vs. Top 5% Peak

Having defined the coincident peak next comes the question of how to measure it. While the single peak method is the simplest, it may not be the most accurate for determining state-level coincident peak requirements. The decision between a Single Peak or the top 5% Peak for resource adequacy analysis depends on the specific goals and characteristics of the power system. The comparison between Single Peak and Top 5% Peak is shown below.

Single Peak

Advantages:

- Simpler and less computationally intensive.
- Provides a clear and straightforward representation of the highest demand

Disadvantages:

- May not capture the full range of peak demand variations throughout the year.
- May underestimate the required capacity if there are multiple significant peaks during different times of day (Solar, Non-Solar)

Top 5% Peak:

Advantages:

- More accurate representation of peak demand variations throughout the year.
- Better captures the impact of multiple peaks.
- Provides a more robust assessment of resource adequacy.

Disadvantages:

- More complex and computationally intensive. Requires more data and analysis.

Single Peak is preferable in cases such as

- If the power system has a single dominant peak and the temporal variations in peak demand are minimal.
- If computational resources are limited or time constraints are tight.

- Countries with relatively stable grids and limited renewable energy penetration use Single Peak.

The top 5% Peak is preferable in cases such as

- If the power system experiences multiple significant peaks throughout the year.
- If there is a need for a more accurate and robust assessment of resource adequacy.
- If computational resources and time are not significant constraints.
- Countries with significant renewable energy integration, fluctuating demand patterns, or regulatory requirements for more accurate peak demand determination use the Top 5% Peak.

In general, the Top 5% Peak method is often preferred for more accurate and comprehensive resource adequacy analysis, especially in power systems with significant variations in peak demand and greater penetration of VRE sources.

Figure 2: Year-wise and monthly demand met in GW

FY	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
2017-2018	157	156	151	152	159	157	154	146	150	155	155	158
2018-2019	159	169	168	166	169	174	169	160	161	160	158	166
2019-2020	175	182	180	174	174	172	162	153	167	169	175	168
2020-2021	131	165	163	169	165	174	168	159	181	189	187	185
2022-2023	207	204	211	189	194	198	186	186	202	209	210	207
2023-2024	214	219	222	207	234	238	220	214	212	221	221	221

The graph above illustrates the national peak demand met on a monthly and yearly basis since 2017-18. It indicates that peak demand tends to fluctuate between May and September, with some exceptions. Consequently, rather than relying on a single profile and peak, it is necessary to consider multiple-year profiles and top 5% peaks.

The following sections discuss two different methods for determining coincident peaks, each suited for different power system needs.

3.2 Methodology Proposed for Coincident Peak Demand

3.2.1 Top 5% Demand Hours Methodology

Determination of coincident peak by considering the top 5% of hourly /sub-hourly (block-wise) demand hours consists of the following Steps.

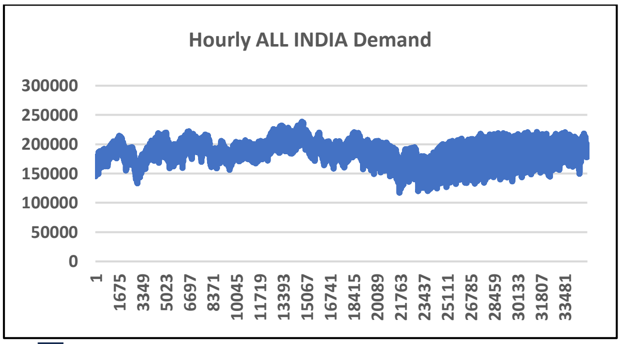
1. Collect the demand profile of each state for the last 2-3 years.
2. Based on the demand profile, project the future demand for the next 2 years using the projected peak demand and energy requirement of each state. Combine the individual state profiles to create a national demand profile.
3. Prepare load duration curve (LDC) for the above demand profile.
4. Filter the top 5% of National Peak demand hours.

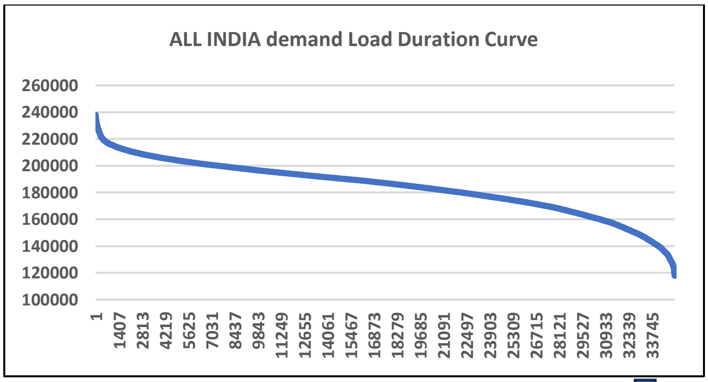
5. The average value of the State Demand during the top 5% demand hours is the Coincident Peak Demand of the state for that year to be met by the respective states.

This step-by-step methodology can be explained through the below illustration

Step 1:

Estimate the demand profile for the next years based on the previous year's demand profile and future peak demand and energy requirement.



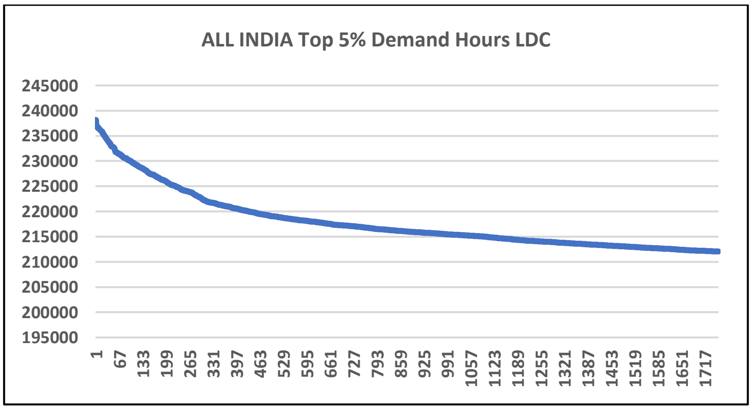


Step 2:

Prepare the load duration curve (LDC) by arranging the demand in descending order.

Step 3:

Filter the top 5% demand hours (0.05*8760= 438 Hours)



Step 4:

Calculate the average of Coincident Demand of States/UT during the top 5% of National demand hours.

Similar exercises can be carried out for the top 10%,15% & 20% Demand Hours.

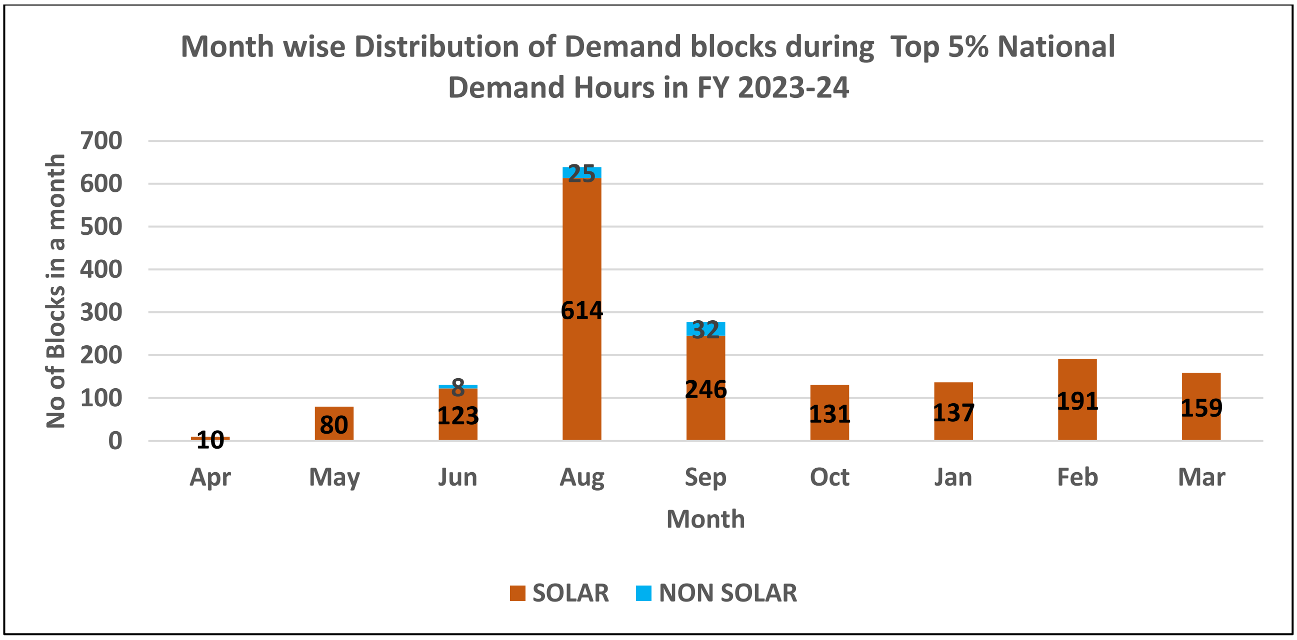
PROS:

1. Easier to calculate.
2. Single Coincident Peak Value for the State/ Distribution Utilities.

CONS:

1. The time of the day (Solar Hours, Non-Solar Hours) is not considered.
2. Average Value may not be adequate to meet the coincident peak.
3. States with high VRE Capacity (Solar and Wind) tied up may face challenges in meeting their coincident peak demand during Non-Solar Hours.

Figure 3: Month-wise distribution of Demand block using the top 5% Demand hour method



(* The Solar Hours considered here are 07-18 H while the rest of the hours fall under the non-solar category)

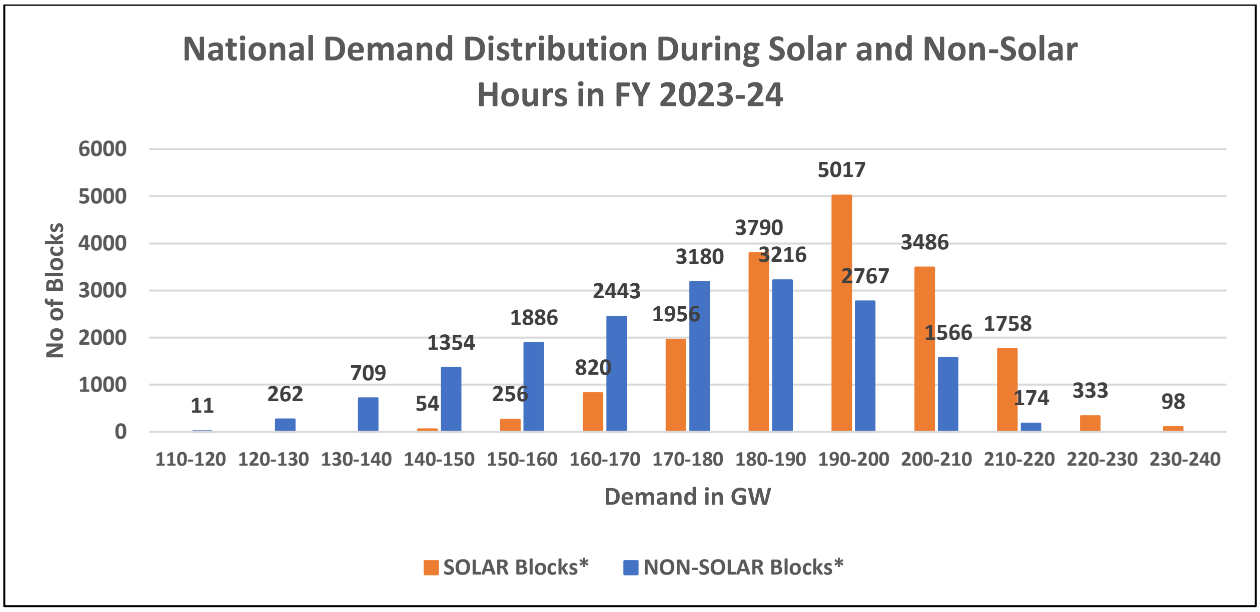
The major issue with the top 5% methodology is the lack of non-solar hours in the top 5% demand hours and the concentration of the top 5% demand hours in only a few months (ex. June-Sept). Of 1756 blocks (5% of 8784*4= 35136 blocks), only 65 blocks occurred during non-Solar hours in FY 2023-24. which severely distorts the analysis towards Solar hour demand while ignoring non-solar hour demand.

3.2.2 Solar Vs Non-Solar Hours

The comparison between solar and non-solar demand hours becomes increasingly significant with the rise in solar capacity addition and the shift of agricultural loads by various states. Typically, solar hours are defined as the period from 7 AM to 6 PM, when solar generation is available. Conversely, non-solar hours refer to the remaining hours outside this timeframe. The top 5% demand hour method does not fully account for the fluctuating availability of solar and wind power, which can significantly impact the grid. This is because the method focuses solely on the peak demand hours, without considering the time-dependent nature of renewable energy sources.

The distribution of demand during Solar/non-solar hours for the year 2023-24 is shown in Figure 4.

Figure 4: Demand Distribution in Solar and Non-Solar blocks



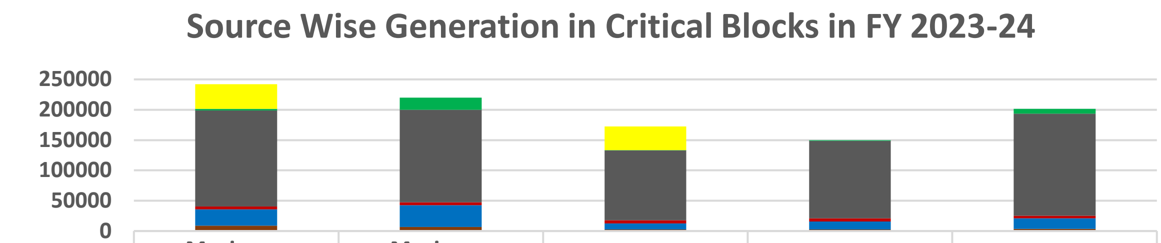
(* The Solar Hours considered here are 07-18 H while the rest of the hours fall under the non-solar category)

As indicated in the graph, although peak demand occurs during solar hours, demand during non-solar hours remains notably significant. The influence of solar versus non-solar peaks will become increasingly important in the coming years, as more demand shifts towards solar hours to take advantage of solar generation.

To analyze the impact of Solar vs. non-solar demand and the impact of intermittency and variability associated with VRE sources, certain critical blocks such as the peak demand block (Solar and non-solar, minimum wind generation block, and minimum VRE block, maximum Coal generation block) have been analyzed which is shown in Figure 5.

As illustrated in Figure 5, during periods of maximum solar demand, solar power contributes approximately 40 GW (approximately 16% of total demand). However, during peak demand periods outside of solar hours, this contribution is 0. This indicates that states with a high percentage of vanilla solar capacity might experience challenges during non-solar hours. Additionally, hydropower is highly seasonal and wind power is intermittent. Therefore, it is essential to analyze the coincident peak demand during both solar and non-solar hours to accurately predict the resource adequacy requirement during the peak demand.

Figure 5: Source-wise Generation During Critical Blocks in FY 2023-24



	Maximum demand block (Solar Hours)	Maximum Demand Block (Non-Solar Hours)	Minimum Wind Generation Block	Minimum VRE generation Block	Maximum Coal Generation Block
SOLAR	40588.9	0	39067.6	0	0
WIND	2551.4	20095.6	237.7	891	7672.5
THERMAL	158056.8	152583.4	115358	127824.3	168496.2
NUCLEAR	4963.1	4757.3	5076.6	5078.6	4319.6
HYDRO	26779.3	35607.5	10188.9	13412	17220.81
GAS	8956.8	6787.4	2487.8	2560.4	3747.1

GAS HYDRO NUCLEAR THERMAL WIND SOLAR

The methodology followed for the calculation of Coincident Peak Demand During Solar and Non-Solar is as follows

1. Collect the block-wise demand for each state & UT for the year.
2. Segregate the demand between Solar and Non-Solar Hours.
3. Determine the top 5% of All India Demand during Solar and Non-Solar Hours separately.
4. Calculate the maximum, percentile (90^{th},80^{th}), and the average value of demand of States/UT among the top 5% values.
5. Check the summation of Coincident demand for different measures (Maximum, percentiles, average) of all the states/UT with the national Peak demand (Solar and Non-Solar) for that year. **The measure that is closest to the National Peak Demand should be considered for the determination of the Coincident peak.**

It should also be noted that if distribution utilities are required to secure capacity equal to the maximum coincident peak demand plus Planning Reserve Margin (PRM), this could result in overcapacity, with the additional capacity remaining underutilized. Conversely, relying on average values might lead to undercapacity, potentially leaving PRM insufficient during peak demand periods. Statistical analysis for the 15-minute demand data for FY 2023-24 & FY 2022-23 shows that the sum of the 80th percentile of the top 5% coincident peak demand values during the year for states or utilities aligns with the national peak demand value. Therefore, states and utilities will be required to maintain a firm capacity based on the 80th percentile of the top 5% of the coincident peak demand values plus the PRM as mandated by the Central Electricity Authority (CEA).

An exercise has been carried out by CEA to showcase the impact of Coincident Peak in both solar and non-solar hours for the different states during FY 2023-24 which is shown in **Annexure A.**

The Coincident Peak Requirement for Solar and Non-Solar hours during the FY 2023-24 is shown in Figures 6 & 7 respectively.

Figure 6

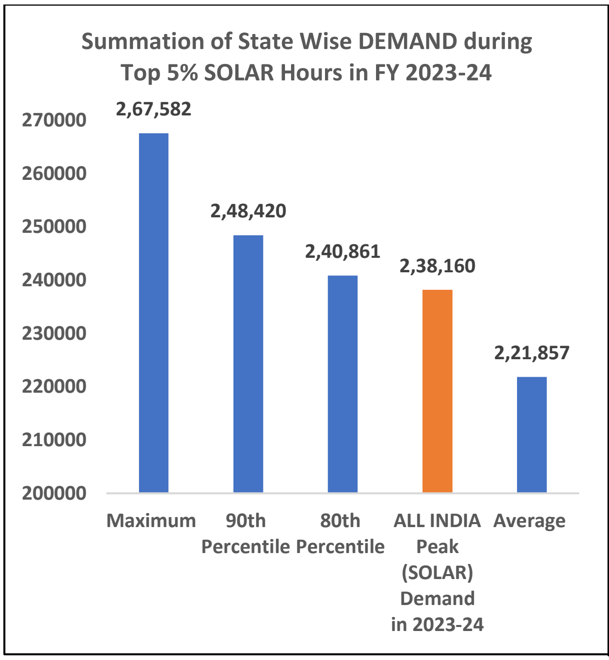
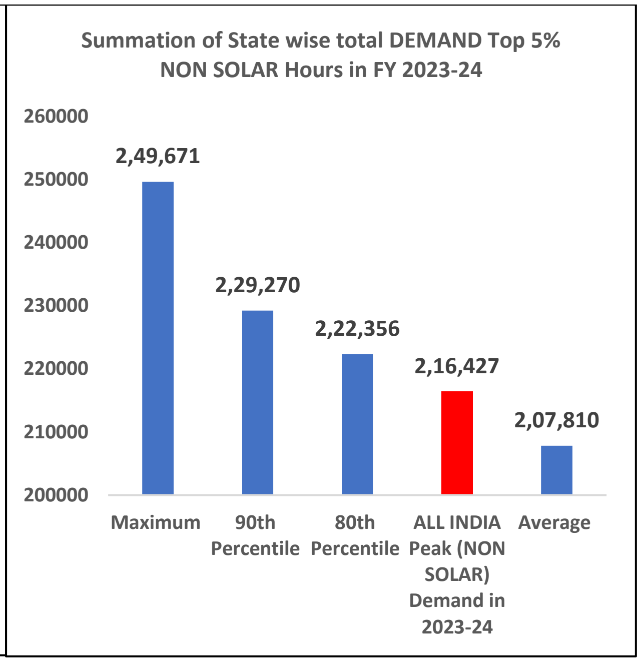


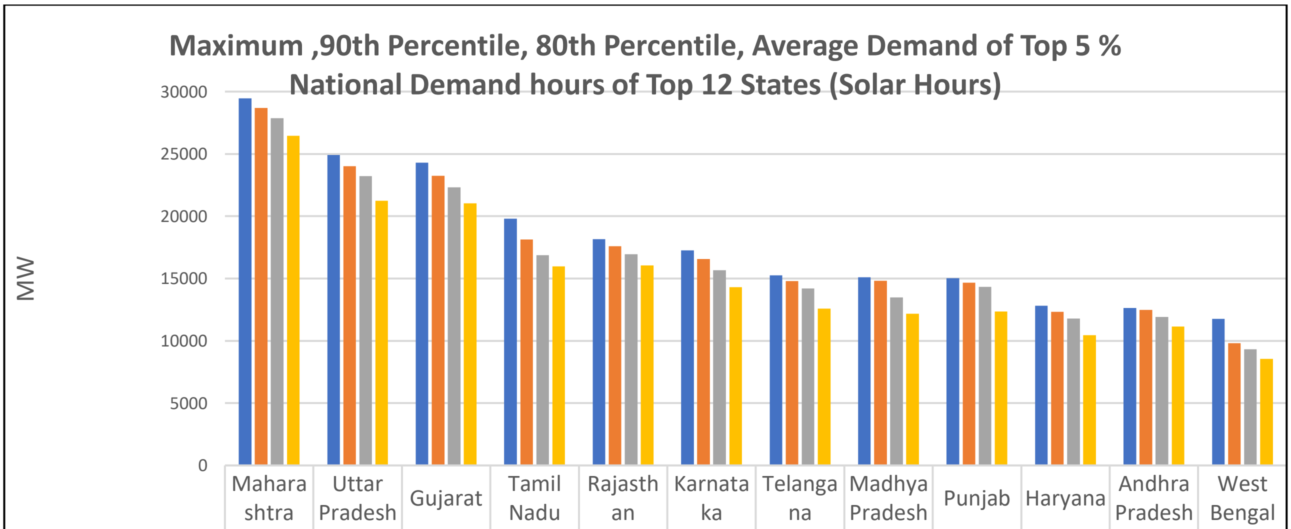
Figure 7



As shown above, the summation of the 80th percentile of peak demand of all states during the top 5% of Solar and non-solar hours closely aligns with the national peak demand observed during both solar and non-solar hours. Therefore, states are required to have firm tied-up capacity corresponding to the 80th percentile of their coincident peak plus National PRM.

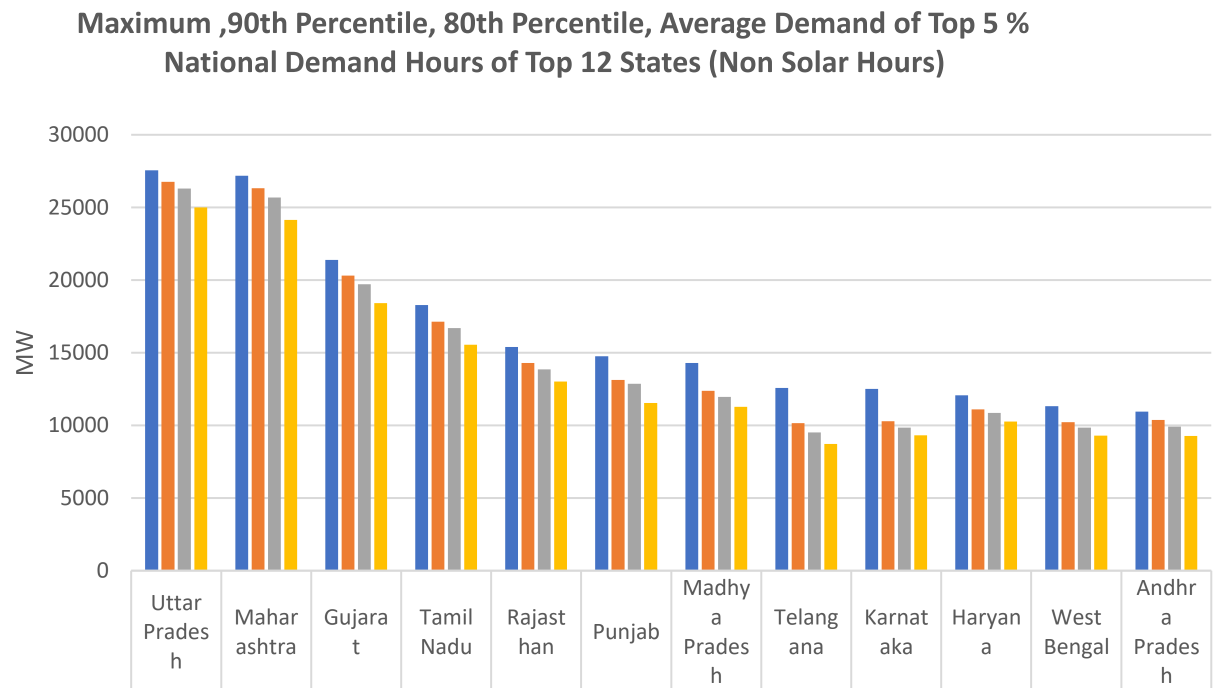
The comparison of maximum, 90th percentile, 80th percentile, and average demand during Solar and Non-Solar Hours of the Top 12 states are shown in Figures 8 & 9.

Figure 8: State-wise Demand percentile during the top 5% National Demand hours in Solar hours



	Maharashtra	Uttar Pradesh	Gujarat	Tamil Nadu	Rajasthan	Karnataka	Telangana	Madhya Pradesh	Punjab	Haryana	Andhra Pradesh	West Bengal
Maximum	29452	24903	24308	19806	18165	17265	15264	15096	15024	12825	12638	11759
90th Percentile	28682	24006	23241	18128	17602	16557	14784	14822	14675	12334	12480	9810
80th Percentile	27875	23214	22312	16885	16950	15668	14201	13489	14327	11801	11921	9332
Average	26444	21245	21042	15976	16050	14311	12580	12161	12356	10450	11141	8561

Figure 9: State-wise Demand percentile during the top 5% National Demand hours in non-solar hours



	Uttar Pradesh	Maharashtra	Gujarat	Tamil Nadu	Rajasthan	Punjab	Madhya Pradesh	Telangana	Karnataka	Haryana	West Bengal	Andhra Pradesh
Maximum	27557	27177	21387	18285	15388	14751	14293	12570	12507	12063	11327	10938
90th Percentile	26773	26333	20305	17131	14286	13129	12376	10157	10298	11103	10229	10383
80th Percentile	26301	25686	19707	16688	13850	12865	11971	9522	9849	10858	9853	9906
Average	25005	24147	18418	15557	13012	11533	11282	8731	9323	10256	9300	9274

Let us understand the above two figures, considering two states i.e. Gujarat and Uttar Pradesh.

Gujarat:

80th Percentile of top 5% coincident non-solar peak demand values = 19707.3 MW

80th Percentile of top 5% coincident Solar peak demand= 22312.1 MW

Therefore, the State Utilities of Gujarat need to secure sufficient tie-up capacity of up to 19,707 * (1+PRM), as recommended by the CEA, for non-solar hours. Since no solar power is available during this period, the capacity credit for solar may be considered as 0, regardless of its contribution during solar peak hours. After meeting the requirements for a non-solar coincident peak, the solar coincident peak of 22,312 MW can be addressed by adding sufficient solar capacity, based on the capacity credit assigned by the CEA.

In the case of Gujarat, it may be noted that **Solar Coincident peak > Non-Solar Coincident Peak**, hence the Solar capacity addition will help Gujarat to satisfy the coincident peak requirement during solar hours.

Uttar Pradesh:

Non-Solar 80th Percentile coincident peak demand = 26300.6 MW

Solar 80th Percentile coincident peak demand= 23214 MW

In Uttar Pradesh, the non-solar coincident peak exceeds the solar coincident peak, unlike in Gujarat, due to differences in demand patterns. Similar to Gujarat, Uttar Pradesh must secure a sufficient tied-up capacity of 26,300.6 * (1+PRM), as recommended by the CEA. Given that the non-solar coincident peak requirement is higher, meeting this requirement will automatically fulfill the solar coincident peak needs in Uttar Pradesh.

It can be observed from the above analysis, that Uttar Pradesh has to tie up other sources of RE such as wind, hybrid, RTC, hydro, Solar with Storage, etc instead of vanilla Solar.

It may be observed that Solar coincident peak demand is higher than non-solar coincident peak demand for most of the states /UT except few states where the evening demand is higher than solar hours demand.

During periods above the 80th percentile of the top 5% coincident peak demand (which is less than 88 hours, calculated as 0.2*0.05*8760 hours), when there is a possibility that the coincident peak demand may exceed the firm capacity of the utilities, they may be permitted to obtain additional power through methods such as power exchanges, banking, and other available options. This will reduce the burden on the part of utilities to procure the maximum of coincident peak demand power through long-term tie-ups. This will also increase liquidity(volume) in the power exchanges and ensure that states/utilities which has excess power may share the capacity with another deficit state. For example, while the maximum coincident peak requirement for Uttar Pradesh is 24903 MW, it is required to have firm term tie-ups corresponding to the 80th percentile which is only 23214 MW during solar hours (as shown in Figure 8).

Based on the above analysis the coincident peak requirement of different states for the FY 2023-24 during Solar and Non-Solar Hours is shown in Figures 10 & 11.

Figure 10: State Wise Coincident peak in MW (Solar hours)

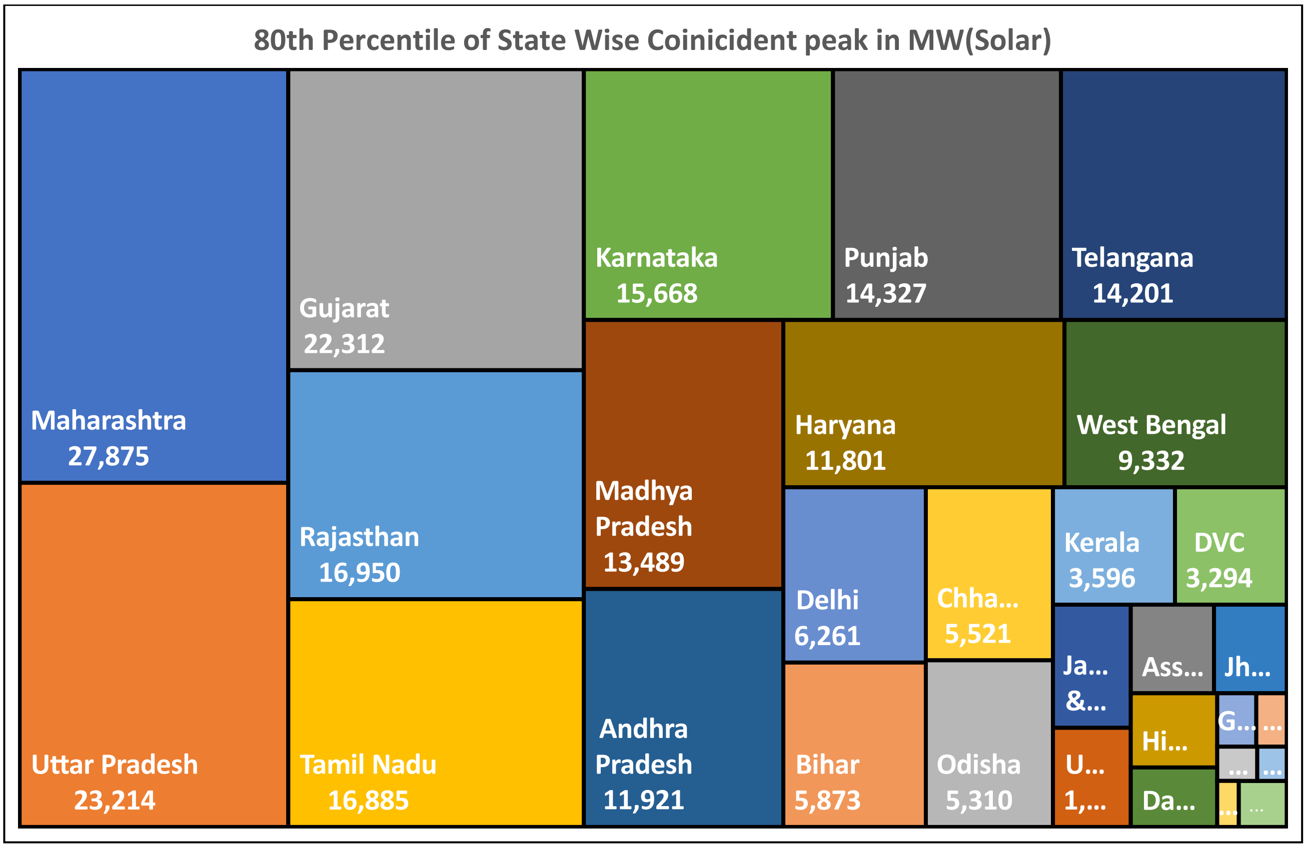
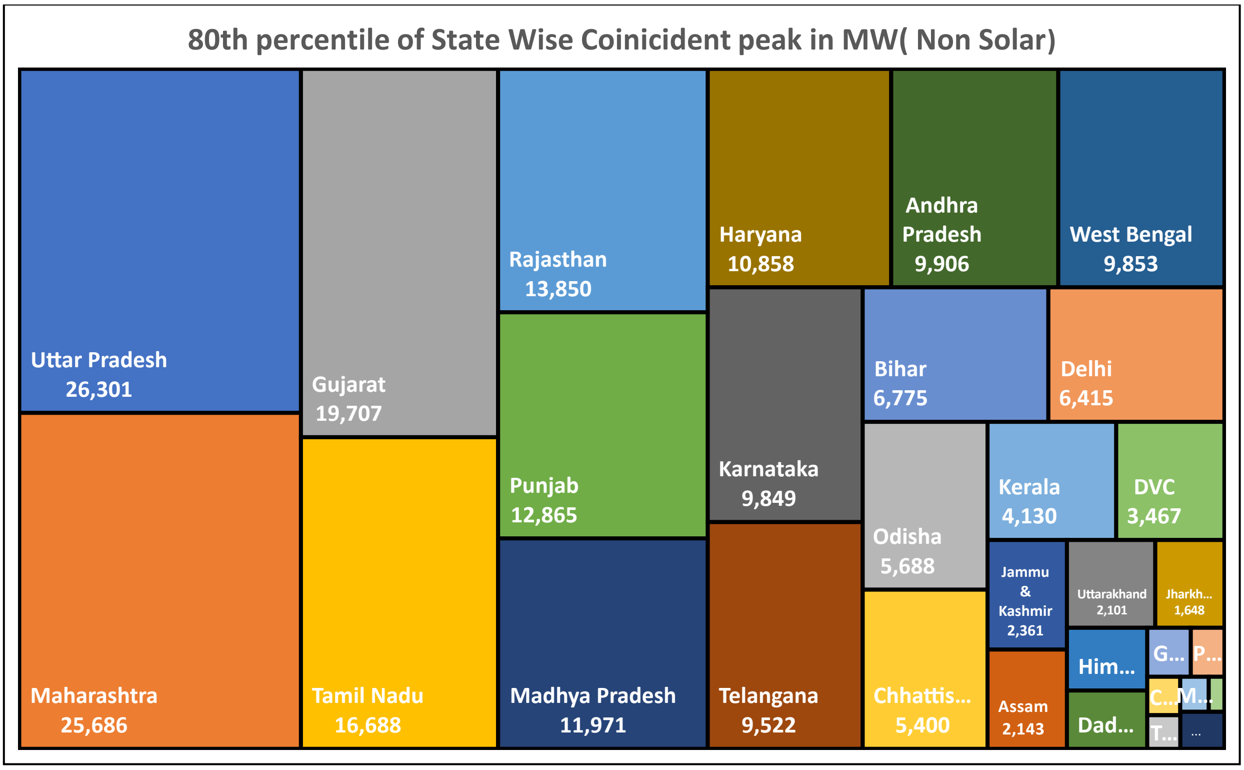


Figure 11: State Wise Coincident peak in MW (Non-Solar hours)



The chart uses a tree map visualization to represent the peak demand of each state, with the area of each rectangle proportional to the state's 80th percentile of coincident peak demand as elaborated in Annexure A. The chart provides a clear visual representation of the distribution of solar and non-solar coincident peak demand across India, highlighting the states with the highest and lowest peak demand. It can be observed that states such as Uttar Pradesh, Maharashtra, Gujarat, Rajasthan, and Tamil Nadu are major contributors towards the national Peak and the combined share of these states is almost 50%.

It's important to note that the coincident peak requirement has been estimated at the state level. State Load Dispatch Centres (SLDCs) of the states having multiple distribution utilities need to analyze the demand patterns of each utility to determine their individual coincident peak requirements.

A similar analysis for FY 2022-23 is enclosed as **Annexure B.**

4.0 Capacity Credit

One of the critical steps in the resource adequacy planning methodology is assigning a Capacity Credit to each generating resource. Capacity credit, as defined in scientific literature, refers to the dependable contribution of a power source or generation technology to meet peak electricity demand reliably within a specified reliability criterion. It is typically expressed as a percentage of the nameplate capacity that can be counted on during peak demand periods. For example, if a generating resource such as wind has a rated capacity of 100 MW and a capacity credit factor of 0.4, its effective capacity credit would be 40 MW only.

Conventional approaches for calculating CC typically treat the power system as a single area without considering transfer constraints and the reliability of interconnectors. However, in multi-area power systems locational aspects are key to assessing trade-offs and synergies arising from transmission, storage, and RES in providing supply adequacy. In this paper, the capacity factor of generating sources has been considered on a standalone basis.

The capacity credit for conventional sources is pretty straightforward (i.e. can be calculated based on the annual availability, and auxiliary consumption). However, for renewable energy sources determining the capacity credit is complicated due to intermittency and variability associated.

The capacity credits for generating resources and demand response resources to meet the national peak shall be estimated by CEA. The capacity credits published by CEA for each resource type may differ between existing and new resources and between resources in different regions. For example, a solar-based power plant in the southern region will have a capacity credit which could be different compared to a solar plant in the northern region. Similarly, an upcoming wind-based power plant could have a different capacity credit compared to an already commissioned wind plant in the same region.

The capacity calculation for Solar & Wind is difficult to calculate due to the following issues.

1. Impact of location (Location Specific profiles)
2. DC/AC ratio of Solar panels
3. Impact of ambient conditions (temperature, precipitation at specific location)
4. Year-on-year variation in generation (5-10% for Solar, up to 50% for Wind)
5. Shift in demand pattern
6. Intermittency and seasonal variation in the generation profile.

Due to the above issues, the determination of capacity credit for VRE sources is a challenge for system planners. This becomes a major issue as more and more VRE capacity is added to the portfolio and a reliable supply of power becomes a challenge during RE Disturbances Demand variation etc.

4.1 Capacity Credit in Resource Adequacy Framework

One of the concepts introduced in resource adequacy guidelines is the concept of Planning Reserve Margin (PRM). The planning reserve margin is a technical metric used in energy system planning and grid operations to ensure sufficient capacity is available to meet electricity demand under various operating conditions and contingencies. It represents the surplus generating capacity above peak demand levels that is planned to maintain system reliability and resilience.

The planning reserve margin is determined based on a specified reliability criterion, typically aiming to maintain a high level of system reliability (e.g., 99.9% or higher). The planning reserve margin requirement is based on two reliability matrices such as **Loss of Load Probability (LOLP)** and **Energy not served (ENS).** This ensures that even during periods of peak demand or unexpected generation outages, there is adequate capacity to meet electricity requirements without risking supply disruptions.

The reserve margin serves as a safety buffer against uncertainties in forecasting electricity demand and unexpected generation failures. It accounts for factors like forced outage of conventional sources, fluctuations in demand, and the availability of intermittent renewable energy sources, transmission outages, etc.

The Resource Adequacy Requirement (RAR) constraint ensures that the total Resource Adequacy (Generation capacity) of the distribution licensee fulfills the Planning Reserve Margin as determined by CEA or by the distribution licensee's studies and approved by the SERC/JERC.

This can be summarized as below.

For LT-NRAP

RAR requirement for ALL INDIA

Total Firm Capacity available = National Peak Demand (ALL INDIA) *(1+ National PRM) Eq(1)

This translates to distribution licenses as

RAR requirement of Distribution licensee

Total Firm Capacity tied up by that Distribution licensee = Contribution to Coincident National Peak*(1+National PRM) Eq(2)

The L.H.S. side of the above equation i.e. firm capacity refers to the dependable output of a power generation source or facility available during peak demand hours. This is arrived at by multiplying the capacity credit of the source within the rated nameplate capacity of the particular generating source. In other words, the above two equations can be rewritten as

∑ Source wise Installed capacity (ALL INDIA) * Capacity Credit of the source= National Peak Demand *(1+National PRM) Eq(3)

∑ Source wise tied up capacity (Distribution licensee) * Capacity Credit of the source= Contribution to National Peak *(1+National PRM) Eq(4)

4.2 Methodology for Determining Capacity Credit of Conventional Sources

Conventional Sources such as coal, gas, and nuclear are reliable and dispatchable sources of power and can be made available during the high demand period. As such the capacity credit of these sources can be estimated as

Capacity Credit of Conventional Sources (Coal, Gas, Nuclear) = Installed Capacity *(1- Auxiliary Power) *Availability

However, it may be noted that the availability of these power plants depends on many factors such as Fuel availability, Planned Maintenance, Forced Outage, etc.

For other sources such as Hydro, Biomass, and geothermal energy, the availability of the plant is highly seasonal. To calculate the capacity credit available from these sources, past generation data for the last 5 years may be considered. The hydro capacity may be divided into two categories Run of the River (RoR) and with Pondage. The capacity credit of RoR capacity may be estimated from past generation data. On the contrary, hydro generators with Pondage may provide higher output during peak demand hours due to available storage associated with these generators.

For energy storage sources such as Pump Storage Plants (PSP) and Battery Energy Storage Systems (BESS), the available capacity can go as high as the rated nameplate capacity as this capacity can be made readily available during high-demand periods. However, due to energy storage limitations, the entire capacity may not be available for a longer period during high-demand hours.

The capacity credit for conventional sources based on the historical generation figures has been estimated in Table 1.

Table 1: Capacity Credit of Conventional Sources

Generation Sources	Capacity Credit(p.u.)
Coal	0.7-0.8
Nuclear	0.6-0.7
Gas	0.7-0.8
Hydro#	RoR- 0.25-0.3, With Storage- 0.6-0.7
Biomass#	0.3
PSP@	0.9-1
BESS@	0.5-1

@ The availability of energy energy-limited sources is dependent on the duration of peak demand hours. For example, the availability of a BESS of 2h is only 50% during a high period of 4h in a day. For PSPs with high storage duration, the capacity credit may be taken as high as 0.9-1.

 # Highly Seasonal in Nature

4.3 Methodology Proposed for Capacity Credit of VRE Sources

The capacity credit of Variable Renewable Energy (VRE) sources, such as solar and wind, is significantly affected by factors like location, temperature, and weather. Their intermittent and variable characteristics make it challenging to assess their capacity credit. Accurate determination of this capacity credit is crucial for evaluating their effectiveness. Various methodologies for calculating the capacity credit of VRE sources have been reviewed in the technical literature. Most system planners consider the top 100 hours or the top 10% demand values to estimate the capacity credit of solar and wind power. The generation of VRE sources in India, particularly wind, is subject to significant fluctuations and cannot be accurately forecasted.

Figure 10: The Contribution from Wind during Top 10% of National Demand in FY 2023-24

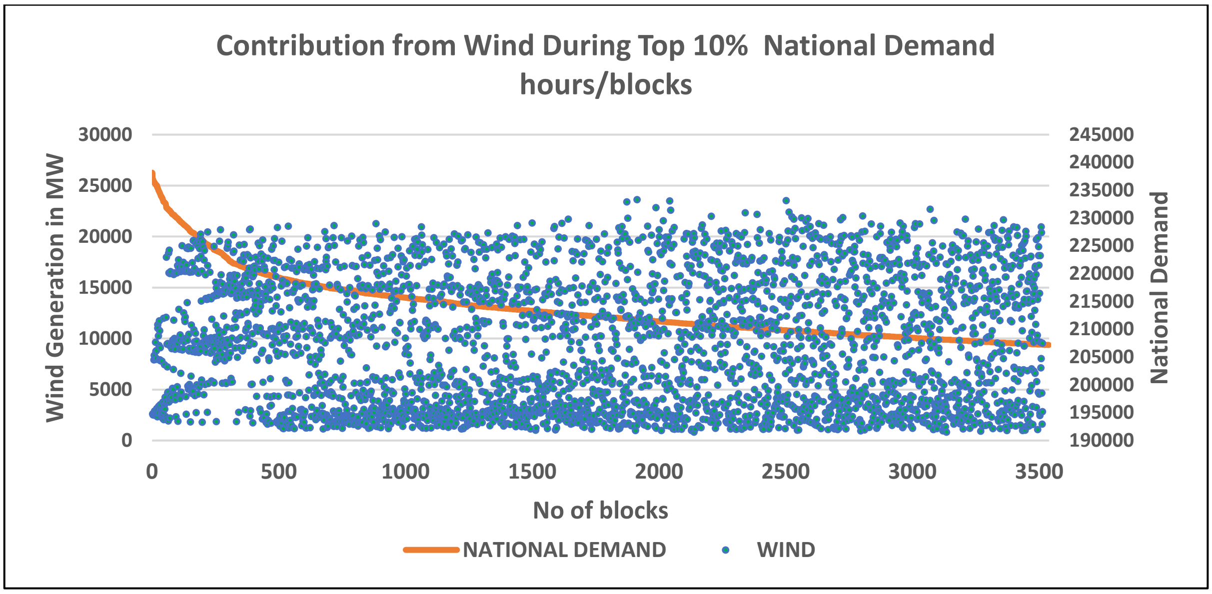
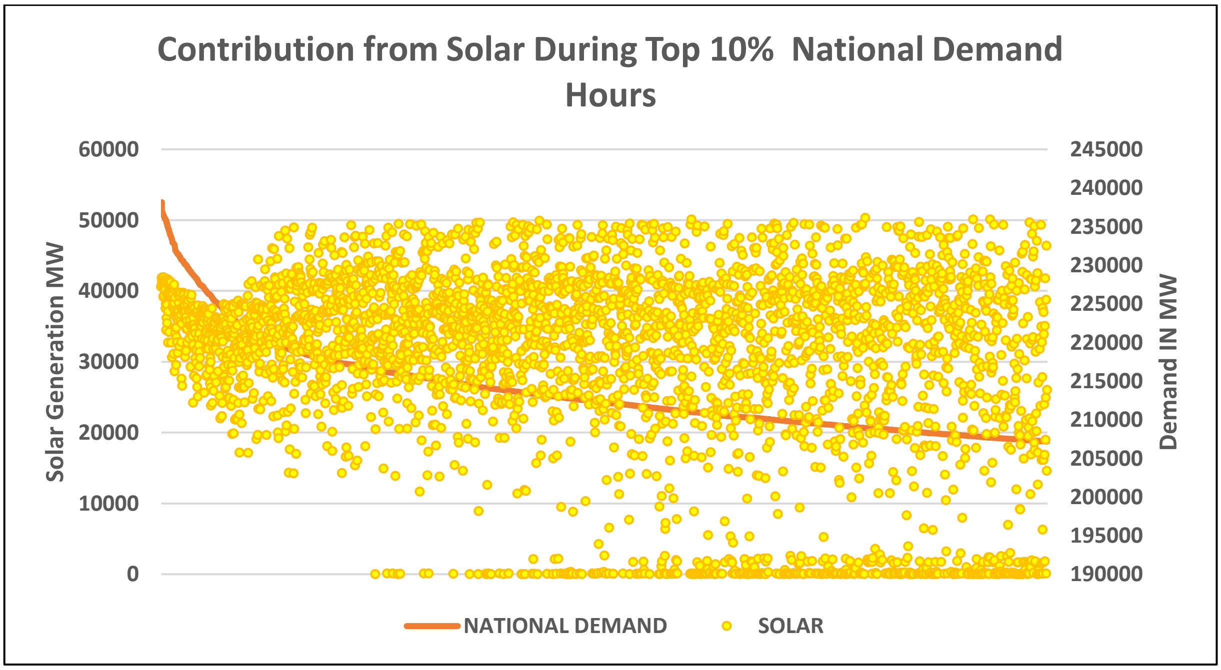


Figure 11: The Contribution from Solar During Top 10% of National Demand in FY 2023-24



The availability of Solar and Wind during the top 10% of National Demand Hours is shown in Figures 10 & 11. The two graphs illustrate the contribution of wind and solar power to national demand in India during the top 10% of demand hours. The wind generation graph reveals a significant degree of variability, with contributions ranging from low to high during peak demand periods. In contrast, the solar generation graph shows a more consistent pattern, with generation generally decreasing as the number of blocks progresses. This suggests that while wind power can contribute significantly to meeting demand at times, its contribution is less reliable than solar power, which tends to be more predictable during peak demand hours.

The frequency distribution of Solar and wind generation during the top 10% of Demand hours is shown in Figures 12 & 13.

Figure 12

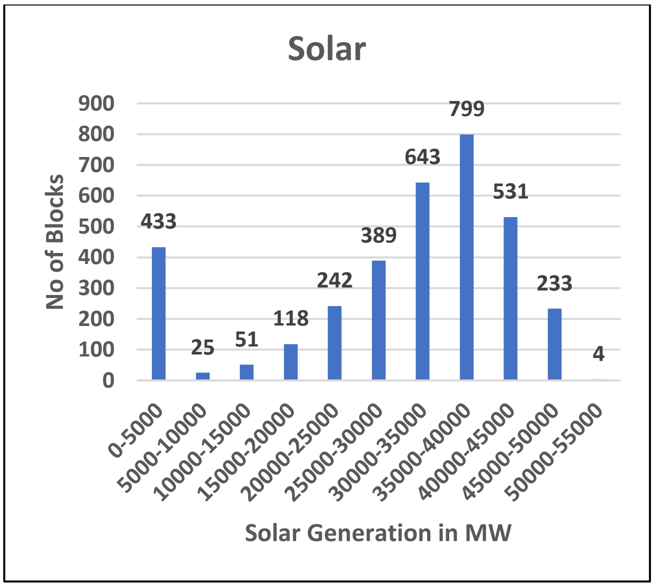
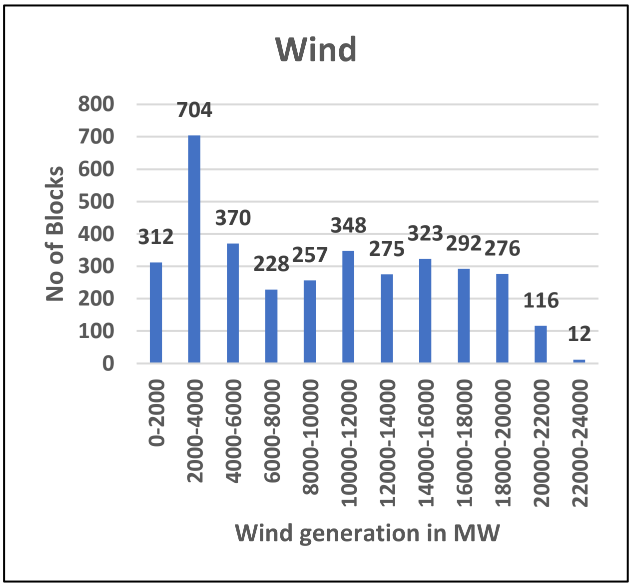


Figure 13



Average Vs Median:

The choice of average vs. median depends on the distribution of the Solar and wind profiles. The presence of extremely high or low values may distort the average value, which may not represent availability. Compared to the average, the median corresponds to the 50th percentile figure, independent of the extreme and outlier values. Due to this, the median of available solar and wind profiles may be considered instead of the average.

4.3.1 Top 10 % Methodology

The methodology consists of the following Steps.

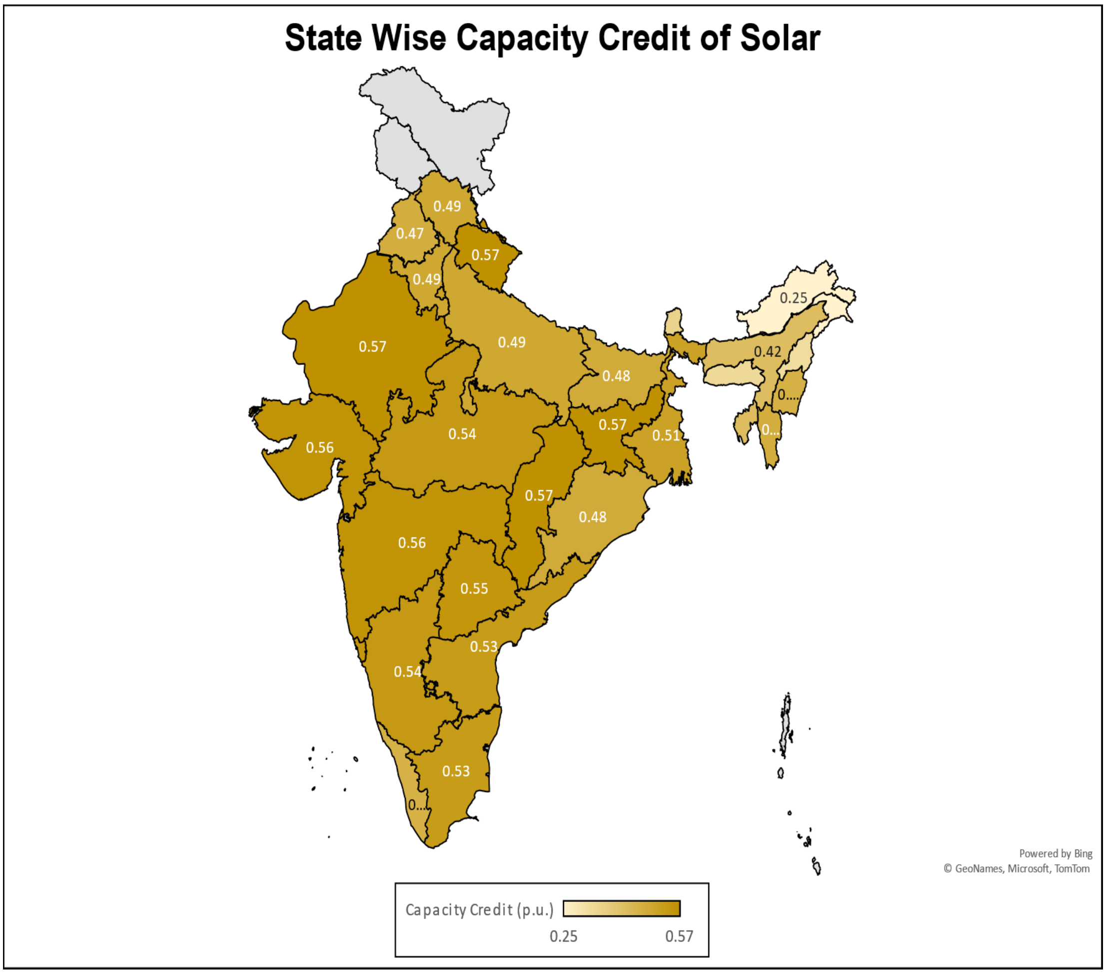
1. Determine the hourly/sub-hourly generation Profile of various sources (i.e. Solar, Wind) for the last 2-3 years.
2. Determine the hourly/sub-hour demand profile at the national level for the last 2-3 years.
3. Filter the top 10% of demand hours.
4. Calculate the median value of generation from various sources per MW of Installed capacity for these top 10% demand hours

5. The value determined is the capacity credit for the respective generation sources.

The median value is recommended instead of the mean or average, as the median is a better representation of resource generation, which is available 50% of the time during peak demand hours. The Distribution of Wind and Solar generation during the top 10 % of national Demand hours is shown in Figures 10 & 11, respectively.

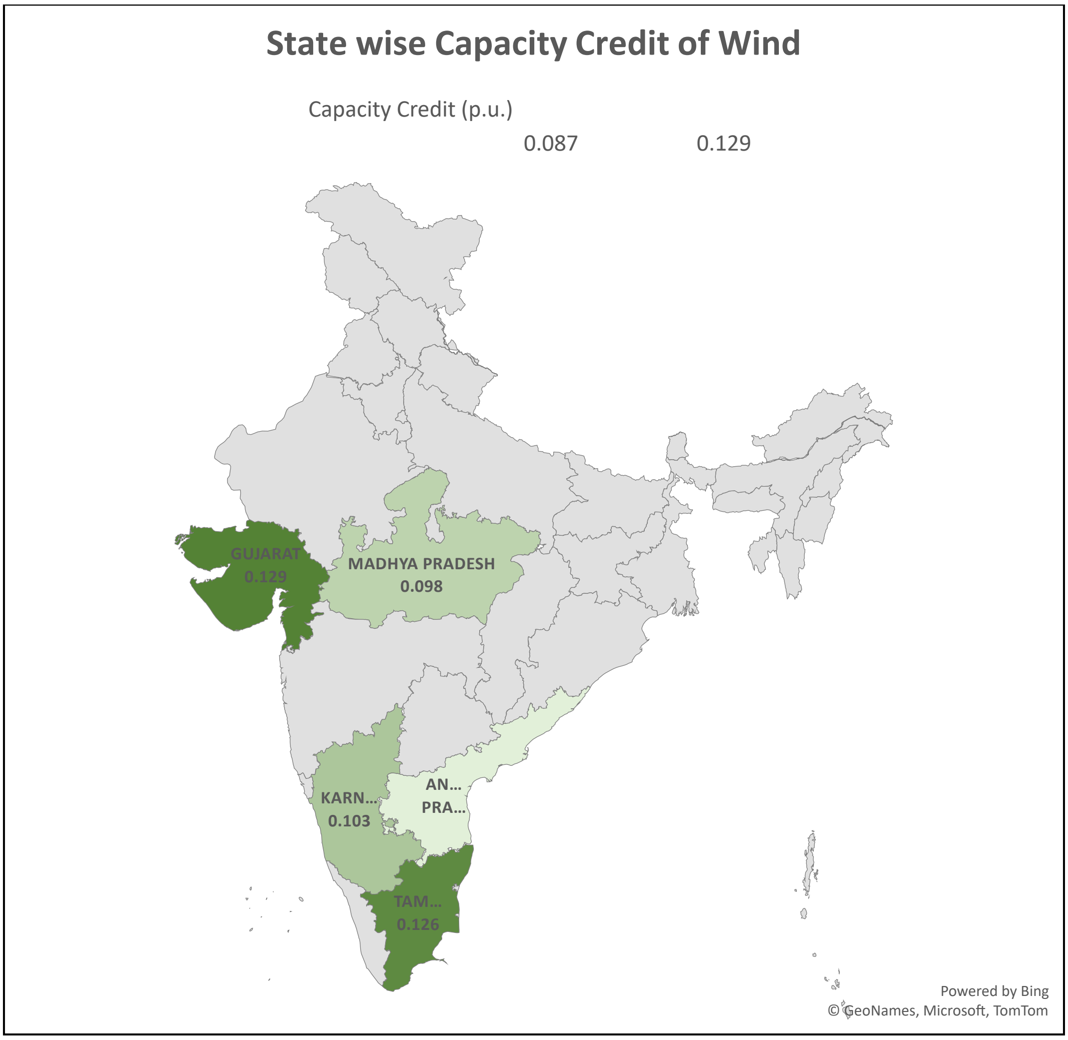
Each state's capacity credits for solar and wind power were estimated using the generation data from the 2023-2024 fiscal year. The calculated capacity credits are presented in **Annexure C**. The state-wise Capacity credit of Solar and wind is shown in Figures 14 & 15, respectively.

Figure 14: State Wise Capacity Credit of Solar



The map uses a colour gradient scale to represent the capacity credit of each state, with darker shades indicating higher capacity credits. States like Rajasthan, Gujarat, Maharashtra, Karnataka, and Madhya Pradesh have relatively high-capacity credits for solar power, suggesting that these regions have a more reliable and consistent solar power generation capacity during the National peak. The map visually represents the spatial distribution of solar capacity credit across India. It can help understand regional variations in solar power generation and its potential contribution to the grid.

Figure 15: State Wise Capacity Credit of Wind



4.3.2 Solar Vs non-Solar Hours

The top 10 % methodology mentioned above has a severe disadvantage, i.e. the capacity credit mentioned for solar and wind (VRE Sources) is time-dependent, and the impact of the Solar vs non-solar period needs to be visible. To address the issues, the following steps need to be followed.

1. Determine the hourly/sub-hourly generation Profile of various sources (i.e. Solar, Wind, hydro) for the last 2-3 years.
2. Determine the hourly/sub-hour demand profile at the All-India level for the last 2-3 years.
3. Filter the top 10 % of demand during Solar and Non-Solar hours.
4. Calculate the Median value of generation from various sources per MW of Installed capacity (both Solar and Non-Solar hours) for these hours.
5. The value determined is the capacity credit for the respective sources.

The availability of variable renewable energy (VRE) sources during the top 10% of demand hours is shown below for both solar and non-solar hours. There is a weak negative correlation between wind power generation and national demand, indicating that wind power generation tends to be lower during peak national demand, especially during solar hours. Solar power availability varies from 20-50 GW during solar hours but does not support the grid during non-solar hours. In contrast, wind power availability is higher during non-solar hours than solar hours.

Figure 16(a)

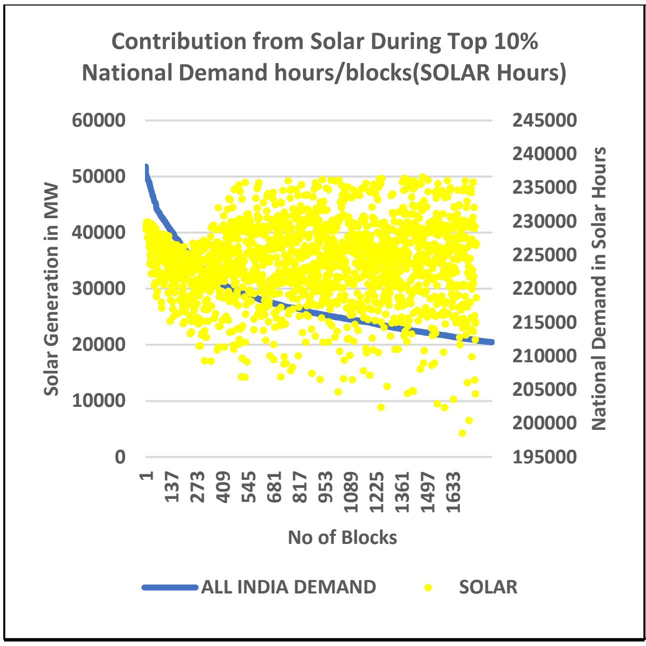


Figure 16(b)

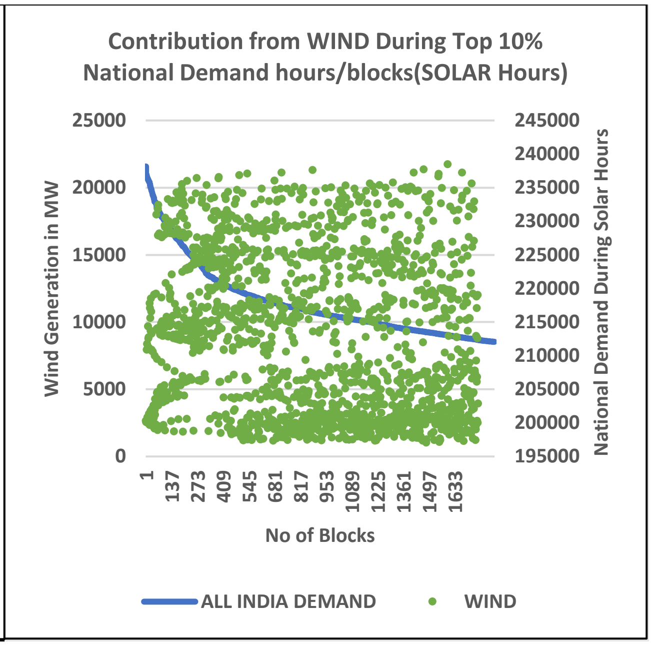


Figure 16(c)

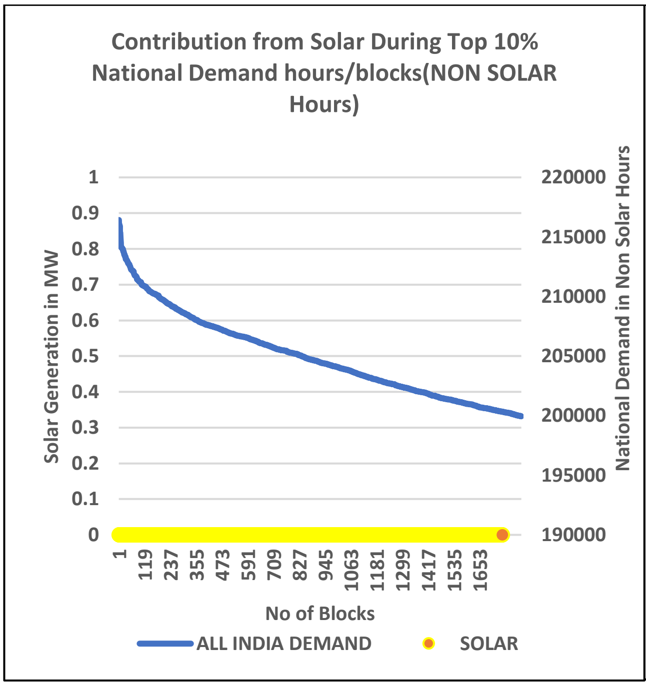


Figure 16(d)

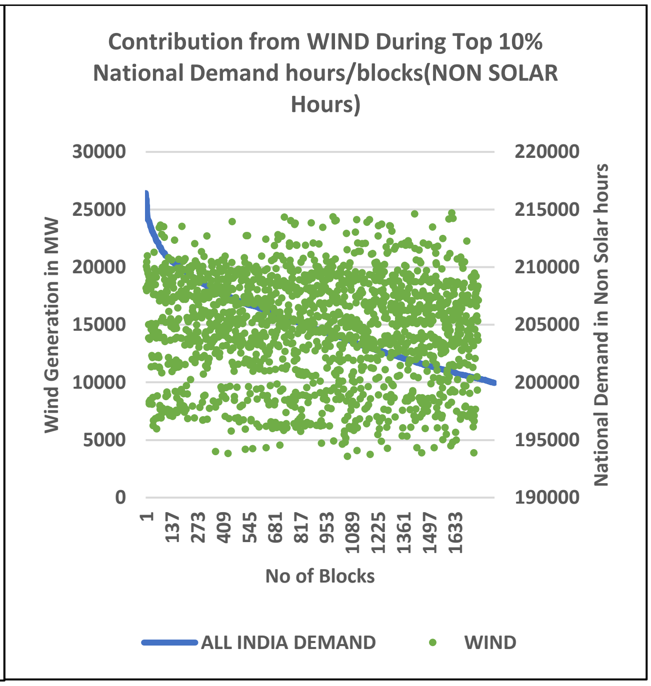
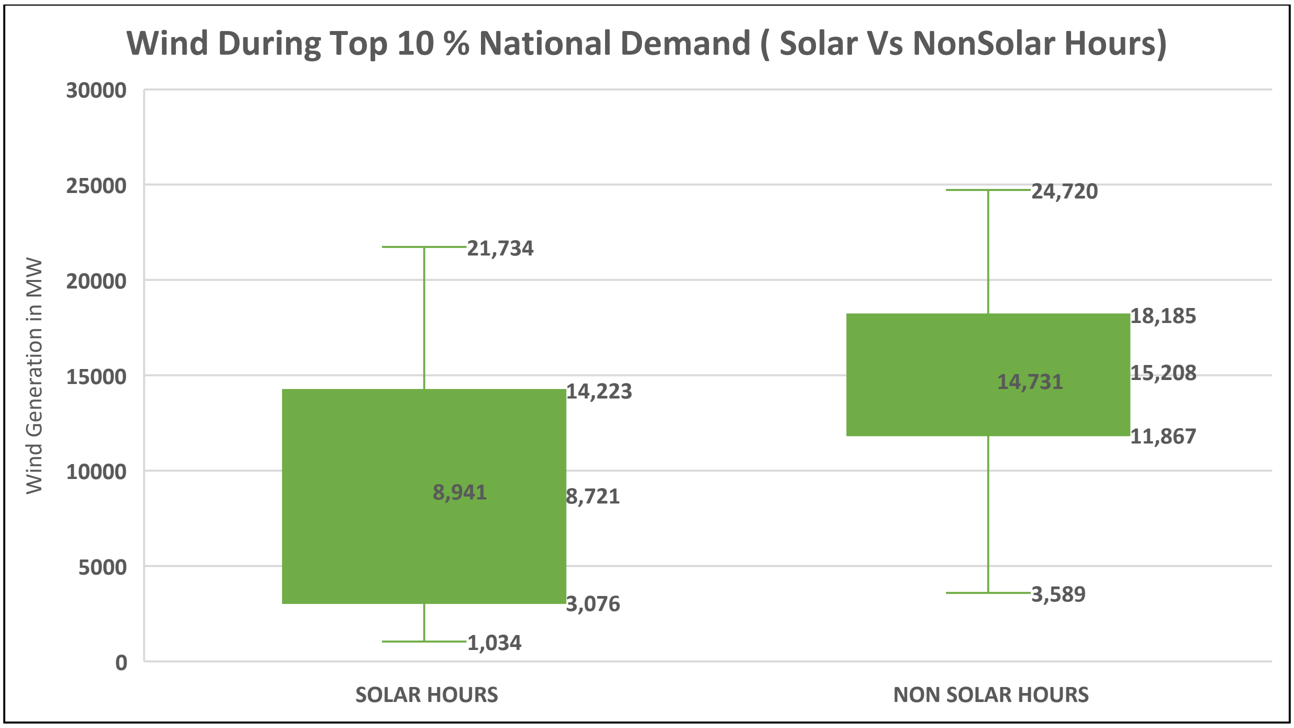
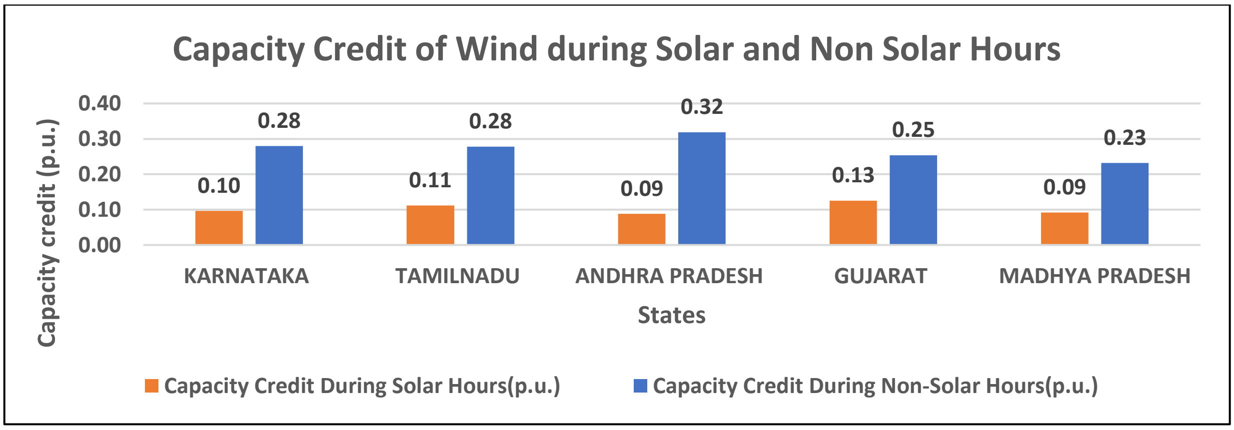


Figure 17: Availability of Wind during Top 10% National Demand (Solar vs. Non-Solar Hours)



The above graph (Figure 17) depicts a box plot comparing wind power generation during the top 10% of national demand in solar and non-solar hours. The median wind generation during solar hours is significantly lower than during non-solar hours. The interquartile range (IQR) for solar hours is also slightly more extensive, suggesting a more comprehensive wind generation spread than Non-Solar Hours. The data indicates that wind power is valuable for meeting peak electricity demand, especially during non-solar hours. The capacity credit for various sources will differ for Solar and Non-Solar hours. While the Capacity credit of Solar during Solar Hours is similar to those shown in **Annexure C**, the capacity credit may be taken as 0 during non-Solar hours. Significant variation is observed in the wind capacity credit in the Solar vs Non-Solar Hours case. The Wind Capacity Credit During the Top 10% of Solar and Non-Solar hours is shown in Figure 18.

Figure 18: State Wise Capacity Credit of Wind (Solar vs non-Solar Hours)



The above chart illustrates the capacity credit of wind power during solar and non-solar hours in five Indian states. Karnataka, Tamil Nadu, and Andhra Pradesh exhibit higher capacity credit during non-solar hours than solar hours. Gujarat and Madhya Pradesh, on the other hand, show relatively consistent capacity credit throughout the day. These findings highlight the potential for wind power to complement solar energy in addressing India's energy needs, particularly in states with favourable wind availability. States like Uttar Pradesh, for example, which have higher coincident peak demand during non-solar periods compared to solar periods, can significantly benefit from the higher capacity credit associated with wind resources during non-solar hours, offering a hopeful outlook for the practical applications of this research.

4.3.3 Capacity Credit with Illustration

To illustrate the impact of capacity credit for both conventional and Renewable sources, the dispatch of each source during the top 10% National Demand Hours of FY 2023-24(Solar and Non-Solar Hours) was analyzed, as shown below.

Figure 19(a): Source Wise Generation During Top 10% Demand (Solar Hours) in FY 2023-24

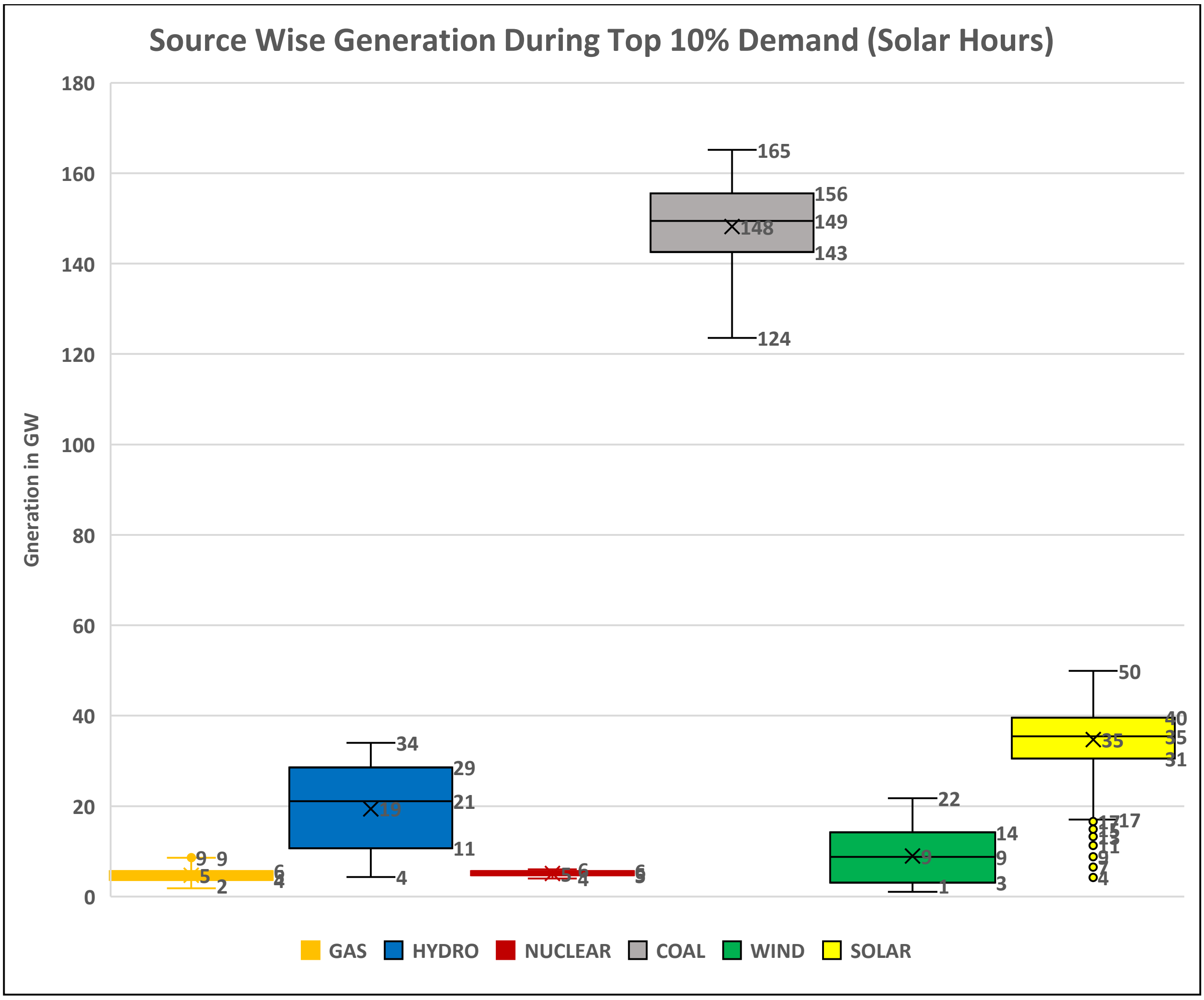


Figure 19(a) illustrates the generation capacity of various sources during peak demand periods (solar hours). Coal-fired power plants consistently generate between 124 and 165 gigawatts (GW), with a median output of 149 GW. Solar energy provides a relatively stable supply of 30-40 GW, while wind generation fluctuates between 3 and 22 GW with a median value of 9 GW.

Figure 19(b): Source Wise Generation in% during TOP 10% Demand Solar Hours in FY 2023-24

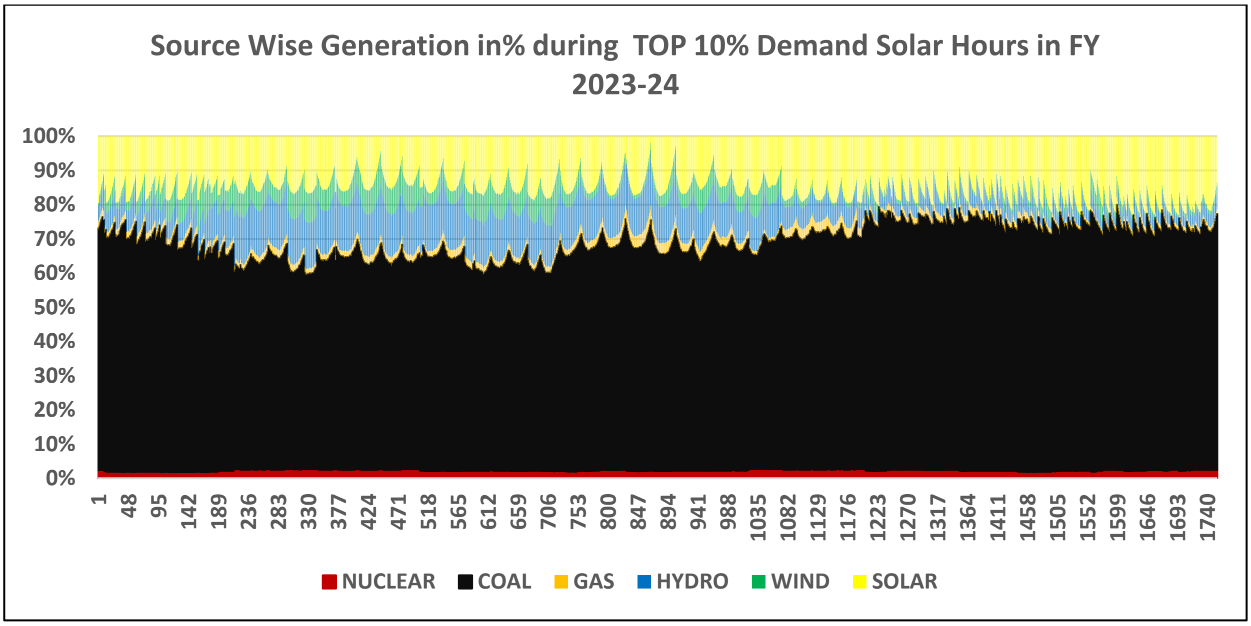


Figure 19(b) presents a stacked column chart depicting the contribution of various energy sources to peak demand during solar hours. Coal consistently supplies 70-75% of the total demand. Hydro and wind power exhibit seasonal fluctuations, as illustrated in the chart. Solar energy typically contributes 15-20% of the total demand during these peak periods.

Figure 19(c): Source Wise Generation During Top 10% Demand (Non-Solar Hours) in FY 2023-24

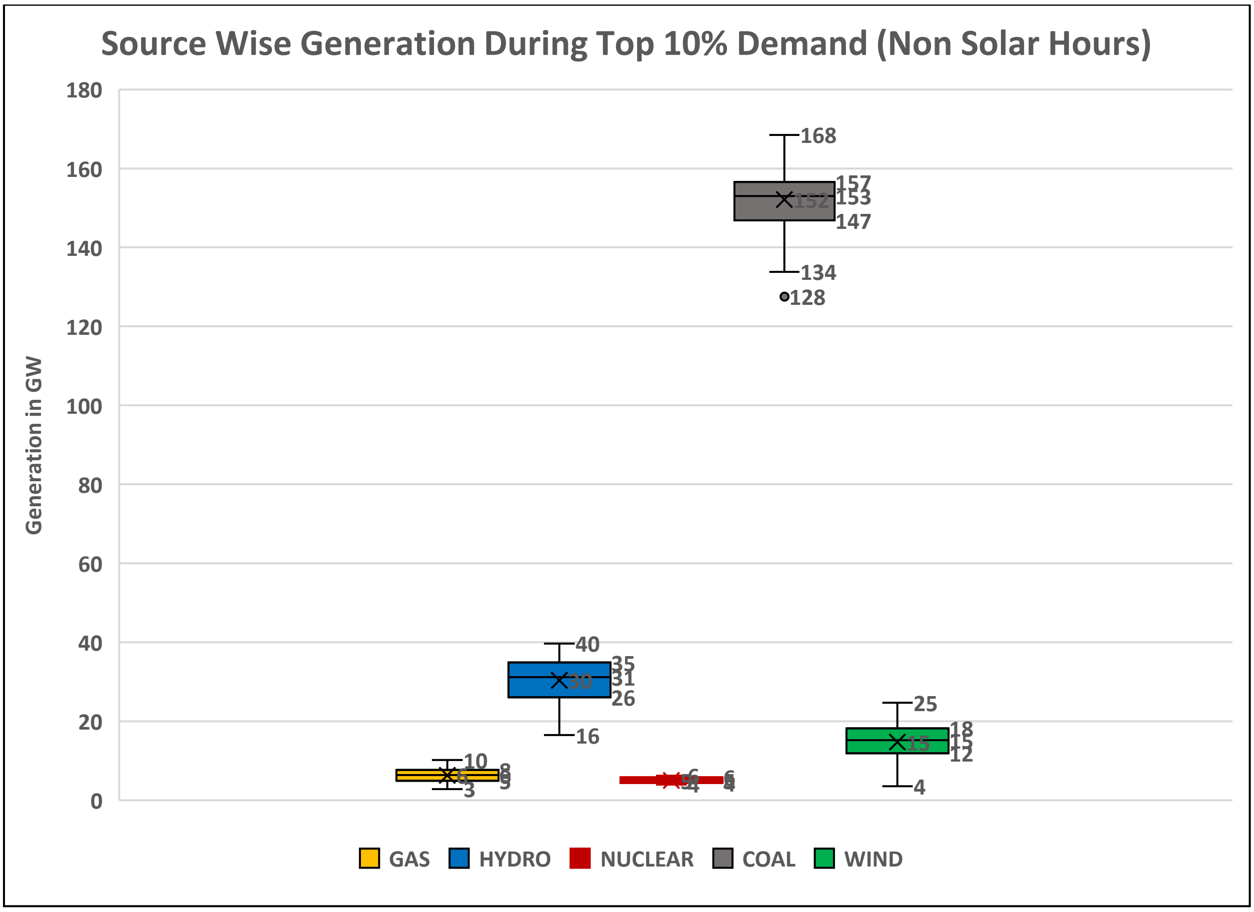


Figure 19(c) illustrates the generation capacity of various sources during peak demand periods (Non solar hours). Similar to the Solar hours, the Coal-fired power plants consistently generate between 134 and 168 gigawatts (GW), with a median output of 153 GW. Compared to solar hours, wind generation is higher and varies between 4 and 25 GW with a median value of 15 GW.

Figure 19(d): Source Wise Generation in % during TOP 10% Non-Solar Hours in FY 2023-24

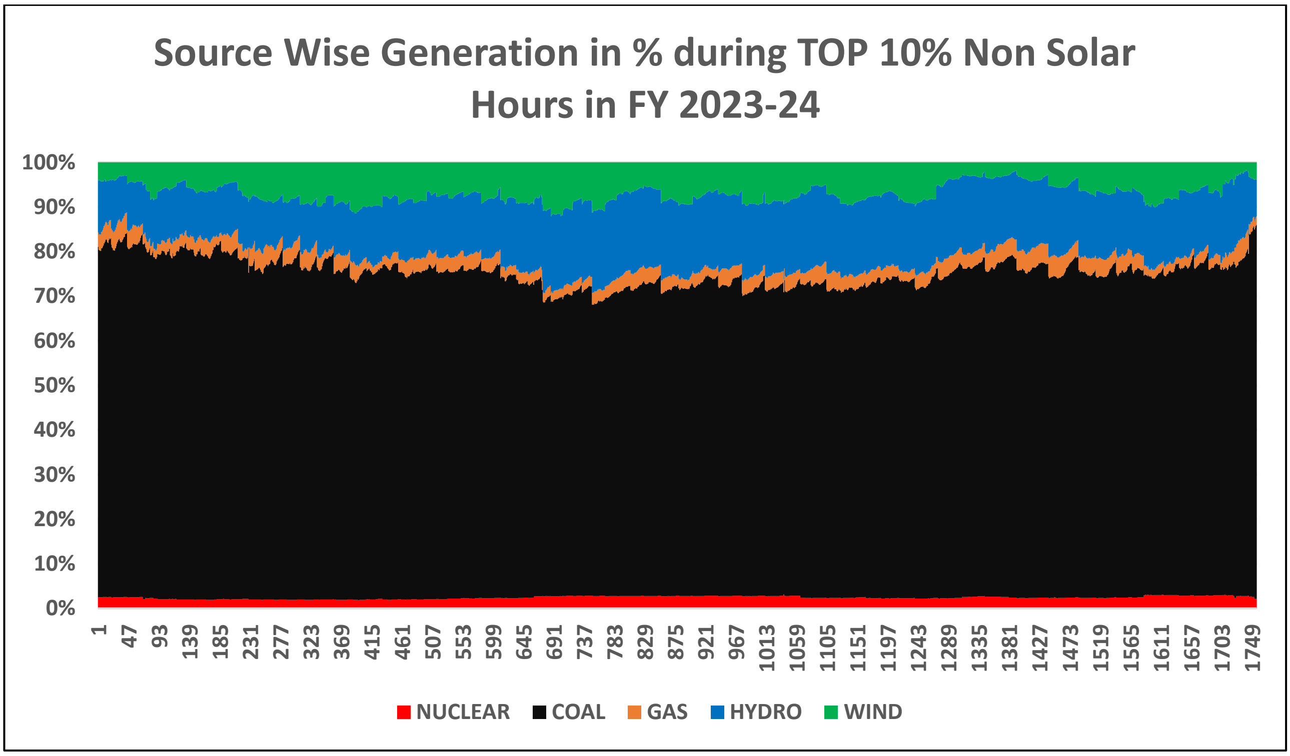


Figure 19(d) presents a stacked column chart depicting the contribution of various energy sources to peak demand during non-solar hours. Coal consistently supplies 75-80 % of the total demand. As contrasted to Solar hours, Hydro generation is typically utilized during the Peak demand hours in the evening and early morning hours. As illustrated in Figure 19(c) and Figure19(d), the share of wind generation in total demand is higher during non-solar hours compared to solar hours

Based on the above analysis it can be concluded that

- Conventional energy sources like coal, gas, and nuclear offer a relatively stable and reliable power supply during both Solar and non-solar periods.
- Solar power generation typically ranges from 30-40 gigawatts (GW) during daylight hours but is unavailable at night.
- Wind power availability is highly variable and influenced by seasonal factors. However, the availability of wind is higher during non-solar hours compared to solar hours.
- Hydro power generation is also subject to seasonal variations. However, hydropower plants with storage capabilities can provide peaking support during evening and early morning hours.

4.3.4 Critical Day Analysis

Compared to the top 5% demand and Solar vs non-solar methodology, which is entirely based on the hourly demand analysis, the Critical Day analysis is a methodology that focuses on critical days that depend on both demand and VRE generation as well as hourly variation. As VRE penetration increases, the Critical Day methodology becomes crucial for assessing system planning. It helps identify potential challenges arising from the variability and intermittency of renewable energy sources.

The critical day analysis is carried out using the k means clustering algorithm. K-means clustering is a popular algorithm in unsupervised machine learning to partition data into clusters. This classification is typically carried out each month by specifying the clusters to be formed. In this case, the demand and RE generation data need to be clustered in three groups each month (High, Medium, Low) and, based on the classifications, divided the days in the month into different categories such as High RE- High Demand, High RE-Medium Demand, etc.

Each day in a month can be broadly classified into one of the cells of the following demand & RE availability matrix.

Demand & RE availability Matrix

RE availability ↑			
	HIGH RE-Low Demand	**High RE-Medium Demand**	**High RE-High Demand**
	Medium RE-Low Demand	**Medium RE-Medium Demand**	**Medium RE-High Demand**
	Low RE-Low Demand	**Low RE-Medium Demand**	**Low RE- High Demand**
		Demand →	

The most critical days are the days of Low RE-High Demand followed by Medium RE-High Demand & Low RE-Medium Demand (Coloured Yellow in the matrix above). Identifying these days for each month will be crucial to highlighting the stress period every month.

Similar to the Critical Day analysis for determining the coincident Peak Demand, capacity credit for VRE sources may be calculated using a clustering algorithm.

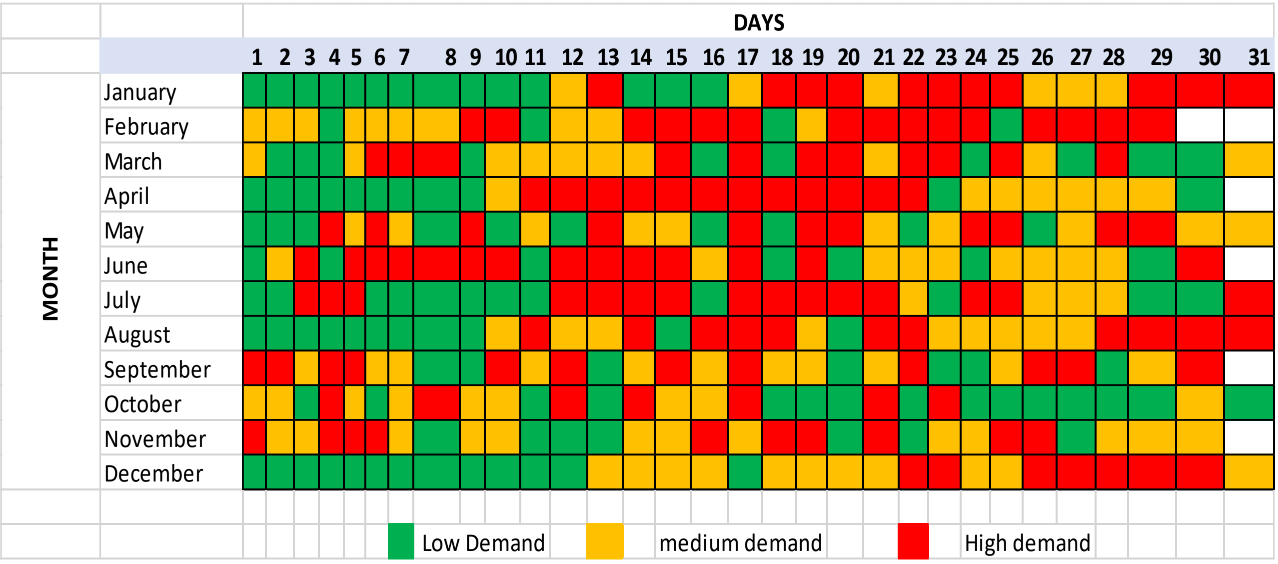
The methodology consists of the following steps:

1. Collect the demand profile and RE generation at the National and state level for the last 2-3 years.
2. Using the k means Clustering algorithm, identify the critical days across the month.

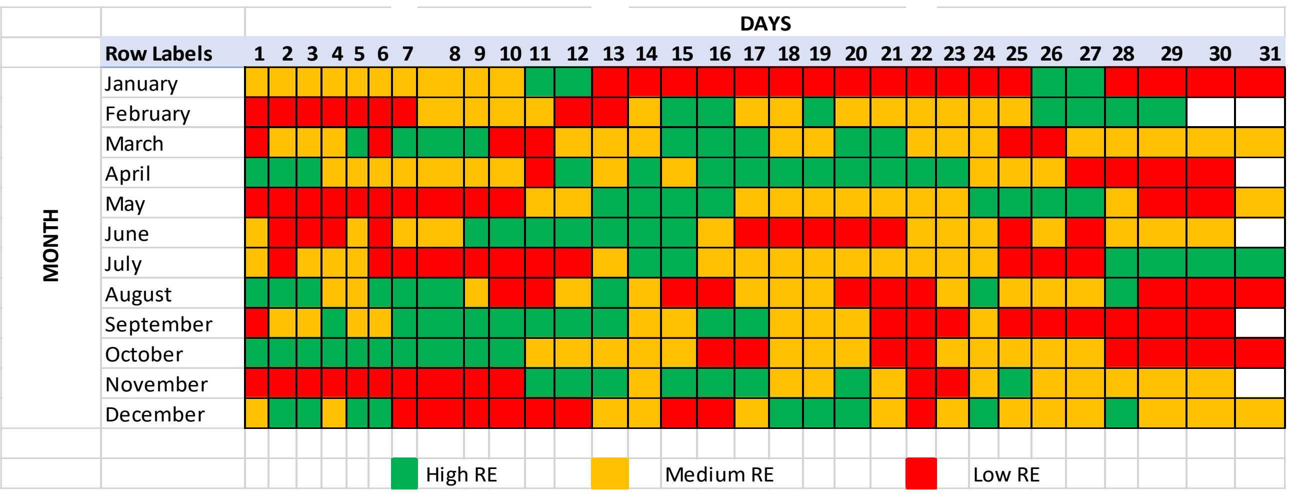
3. Calculate the median value of the generation from various sources per MW of installed capacity during those critical days (both solar and Non-Solar Hours).
4. The value determined is the capacity credit for the respective sources.

The k-means algorithm used in this method is explained in detail in **Annexure D**.

Based on the above algorithm, the high-demand, mid-demand, and low-demand days of each month for the FY 2023-24 have been identified below. The heatmap visually depicts monthly electricity demand fluctuations. Each cell's colour—green, yellow, or red—represents low, medium, or high demand, respectively. Analysing the colour patterns can estimate the peak demand days on a monthly or seasonal basis.

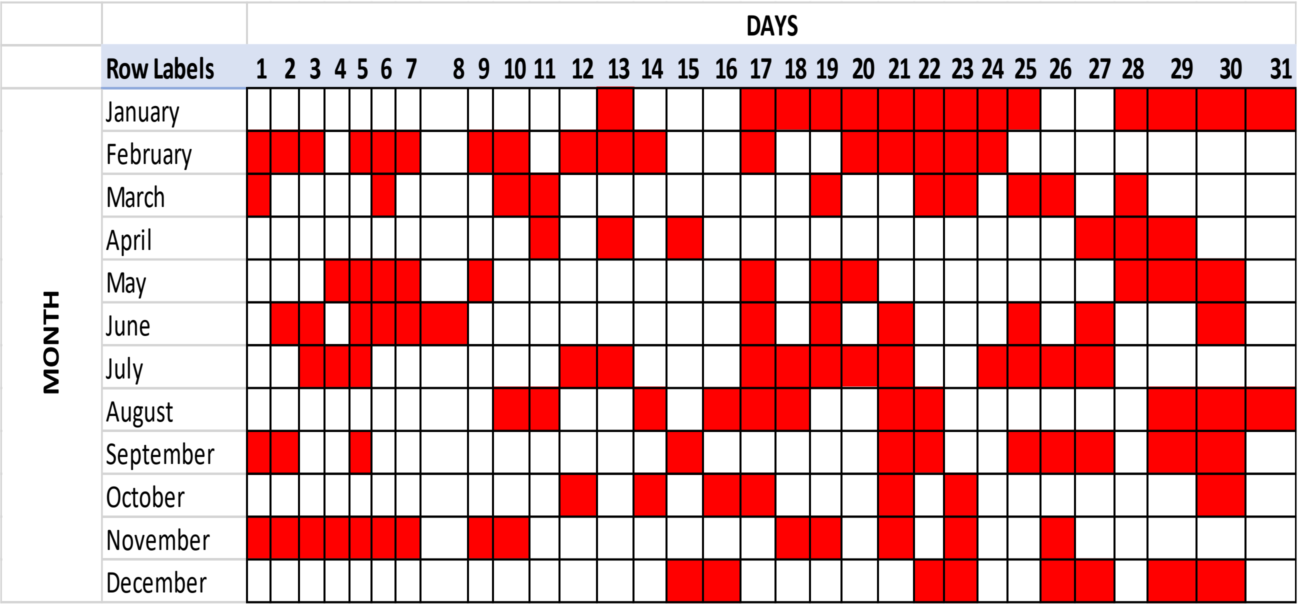


Similarly, each month's high RE, mid-RE, and low RE days are shown below.

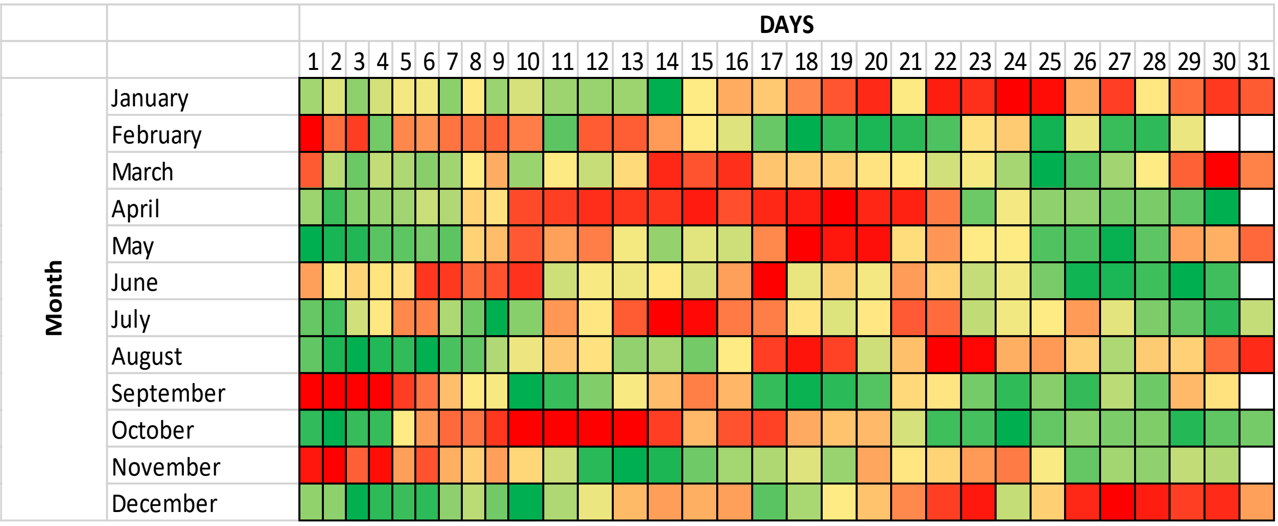


Based on the above clustering of demand and RE, the Critical days of each month (High Demand - Low RE, Medium Demand-Low RE & High Demand Medium RE) have been marked as RED below table, while the rest of the days have been marked white.

Critical days of each month in FY 2023-24



Critical days can be validated by examining average daily market (DAM) prices in power exchanges. On these days, electricity demand is higher, while renewable energy (RE) supply is lower, leading to increased DAM prices compared to other days of the month. The heat map of average DAM prices for each day in a month in FY 2023-24 is shown below.



As shown in the graphs, the days marked in red in the first graph generally align with the days marked in red in the second graph. This indicates that periods with high demand and low to moderate renewable energy availability often coincide with higher exchange prices, suggesting these are critical periods for grid management.

The Capacity credit has been estimated by calculating the median value of state-wide Solar and Wind profiles during Solar and Non-Solar Hours, respectively, during the critical days, which is given in **Annexure E,** which is also shown in Figures 20 & 21.

Figure 20: Capacity Credit of Solar (State Wise) (Critical Days)

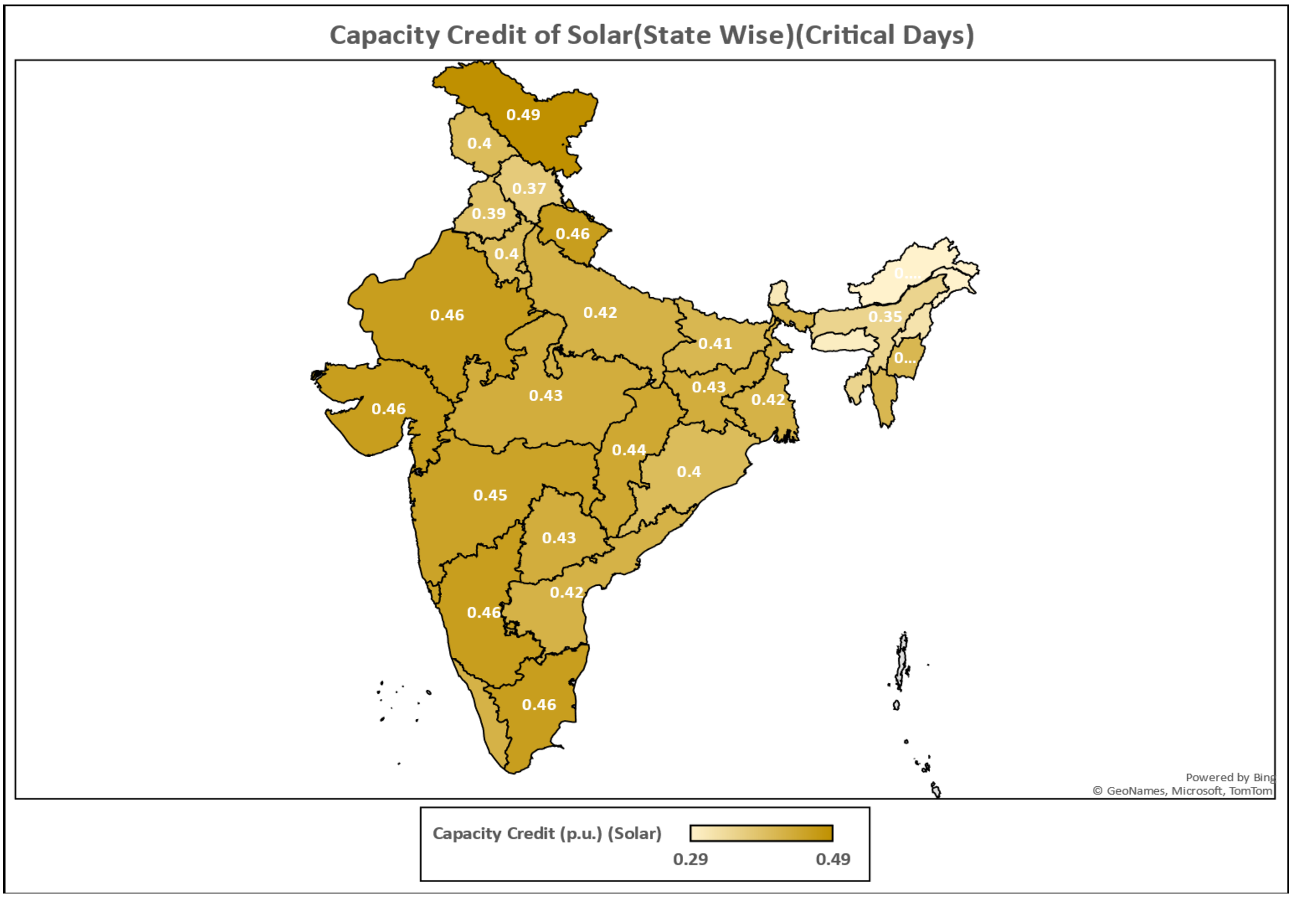
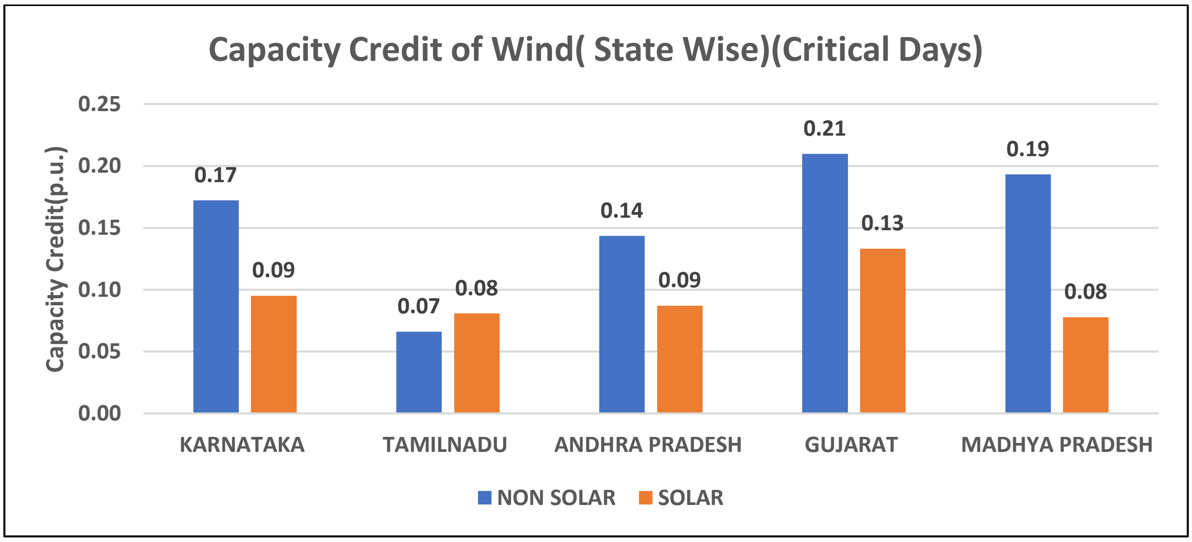


Figure 21: Capacity Credit of Wind (State Wise) (Critical Days)



The critical days (using the k means clustering algorithm) provide significant advantages compared to the top 10% methodology, such as:

- Identify multiple clusters of peak demand periods(days) with Low and Medium RE generation days.
- Identify crunch periods that may not necessarily peak demand periods.

4.4 Capacity credit of Resources such as FDRE, Hybrid

FDRE (Flexible Demand Response Entities) and **hybrid resources** are experiencing significant growth in India, driven by policy initiatives, technological advancements, and the increasing need for grid flexibility. These innovative solutions offer a valuable alternative to traditional power generation, helping to address peak load challenges and mitigate the need for additional fossil fuel-based plants. By effectively balancing supply and demand and managing the intermittency of renewable energy sources, these resources contribute significantly to grid stability. As a result, distribution utilities increasingly turn to FDRE and hybrid resources as a preferred choice over standalone solar and wind power systems. Determining the capacity credit of hybrid resources can be complex due to the combination of technologies, geographic location, and available storage capabilities. The distributed nature of hybrid systems, often incorporating solar, wind, and battery components in different places, introduces additional transmission and real-time control challenges, which can impact their overall availability and reliability.

Recent tenders for hybrid resources often outline specific requirements for monthly and annual availability, ramping capabilities, and minimum generation output. These criteria provide a foundation for estimating the capacity credit of such systems. As hybrid technology advances, capacity credit may be determined based on the actual generation profile and predictive forecasting models.

4.5 Challenges in Estimation of Capacity Credit of VRE Sources

The capacity credit of Variable Renewable Energy (VRE) sources is significantly influenced by demand patterns, weather conditions, and environmental factors and is subject to change over time. As more VRE is integrated into the grid, the incremental capacity credit of newer resources may decrease compared to existing ones, potentially affecting the economic viability of renewable energy projects.

To mitigate these challenges, the following strategies need to be considered:

1. **Enhance VRE Reliability**: Combine VRE sources with energy storage systems to improve their reliability and availability, particularly during low renewable energy generation periods.
2. **Demand Shift**: Implement demand-side management programs to encourage consumers to shift their energy usage to periods of high VRE generation, such as during sunny hours.
3. **Flexible Thermal Power**: Mandate flexible operation of thermal power plants to enable them to ramp up or down quickly, supporting VRE integration and maintaining grid stability.
4. **Capacity Markets**: Establish capacity markets to facilitate the sharing of resources during periods of capacity crunch, ensure grid reliability, and provide a fair compensation mechanism for all participants.

5.0 Capacity Credit Methodology Across the Globe

USA

The concept of capacity credit in the USA began with the need to ensure a reliable electricity supply amid growing demand and the diversification of generation resources. Early methods focused primarily on evaluating the reliability of conventional power sources like coal and gas. The formation of RTOs (Regional Transmission Organizations) and ISOs (Independent System Operators), such as PJM Interconnection and CAISO, brought about standardized approaches to capacity credit assessment, reflecting the new market dynamics and the need for robust resource adequacy.

In the USA, the capacity factor is closely interlinked with the capacity market. Many regions have established capacity markets where generators are compensated for providing capacity to meet the peak demand. Capacity credit is critical in determining how much capacity a generator contributes to meeting reliability requirements.

- **PJM Interconnection:** PJM operates a capacity market in which capacity credits are awarded based on resource reliability. The capacity market ensures sufficient generation to meet peak demand and maintain system reliability.
- **New York Independent System Operator (NYISO):** NYISO also operates a capacity market that uses capacity credit to determine the reliable contribution of various resources.

Federal Energy Regulatory Commission (FERC) oversees the operation of RTOs and ISOs, setting regulations and standards that influence capacity credit assessments and resource adequacy planning.

European Union

The EU employs Effective Load Carrying Capacity (ELCC) to assess the capacity credit of renewable resources such as wind and solar. ELCC measures the contribution of these resources to peak demand, accounting for their variability. Capacity mechanisms ensure sufficient reliable capacity is available, with capacity credit playing a role in these mechanisms. The European Network of Transmission System Operators for Electricity (ENTSO-E) and the European Commission work to harmonize capacity credit methodologies across member states, ensuring consistency and reliability in resource adequacy planning.

Australia

The National Electricity Market (NEM), established in 1988, is responsible for capacity credit assessments and ensuring that sufficient generation resources are available to meet peak demand in Australia. The Australian Energy Market Operator (AEMO) uses methodologies such as capacity factor analysis and Effective Load Carrying Capacity (ELCC) to evaluate the reliability of generation resources. The Australian Energy Regulator (AER) and the Australian Energy Market Commission (AEMC) provide regulatory oversight and guidelines for capacity credit assessments, ensuring consistency and reliability in market operations.

6.0 Conclusion

Capacity credit plays a pivotal role in the policy framework for resource adequacy, serving as a critical measure for evaluating and ensuring the reliability of the electricity supply system. In the context of a policy framework, capacity credit assesses the contribution of various power generation sources towards meeting peak demand and maintaining grid stability. Effective resource adequacy planning relies on understanding how different generation assets, including conventional sources (coal, nuclear, gas) and renewable sources (wind, solar), contribute to overall system reliability.

Capacity credit is a critical metric for evaluating the reliability of different power sources during peak demand. It ensures that the grid can meet high-demand scenarios effectively. By accurately assessing capacity credit, policymakers and grid operators can better integrate diverse energy sources, balancing traditional and emerging technologies to achieve reliable and sustainable power systems.

Accurate capacity credit assessments are crucial for effective resource planning and decision-making, ensuring adequate generation resources are available to meet future demand. Capacity credit can vary with evolving grid conditions, technological advancements, and regulatory shifts. Regular reassessment and adjustment are necessary to reflect these changes accurately. As the energy landscape transitions towards sustainability, integrating intermittent renewable resources requires periodic assessment and reassessment of their capacity credit values to ensure a balanced and reliable grid.

This concept paper has tried to explore various methodologies for estimating coincident peak and capacity credit. As highlighted, coincident peak assessment is crucial from the state and distribution utilities' perspective. Accurate assessments allow them to quantify the firm capacity (guaranteed power supply) they need to contribute to meet their share in national peak demand.

The paper suggests that the solar vs. non-solar methodology may be a better approach for estimating coincident peaks, especially considering factors such as agricultural load shifting and the focus on adding solar capacity. This method could be more relevant than the traditional top 5% demand hour methodology.

The paper also explored various methodologies for estimating the capacity credit of different resources, including the top 10% demand hours, solar vs. non-solar, and critical days methods. Capacity credit estimation is essential for determining the capacity requirements tied up from various resources by state and distribution utilities to meet their coincident peak demand obligations.

Based on the analysis, the critical days methodology suggested in the paper is well-suited for estimating the capacity credit of variable renewable energy (VRE) sources, particularly for solar and non-solar hours. By focusing on days with adverse conditions for VRE, the Critical Day analysis provides a more realistic assessment of system performance and resilience. As more VRE is integrated into the system, the critical days methodology becomes even more suitable compared to other methodologies. This approach provides a more accurate representation of the actual performance of VRE sources during critical conditions.

Annexure A

State Wise Coincident Peak During Solar Hours During FY 2023-24

State/UT	Maximum of Coincident Peak (top 5%) _SOLAR Hours	90th Percentile of Coincident Peak (top 5%) SOLAR Hours	80th Percentile of Coincident Peak (top 5%) SOLAR Hours	Average of Coincident Peak (top 5%) SOLAR Hours
Chandigarh	399.0	373.6	346.2	296.3
Delhi	7433.2	6708.7	6260.8	5595.2
Haryana	12825.3	12334.0	11800.8	10449.8
Himachal Pradesh	2057.1	1875.2	1609.0	1477.0
Jammu & Kashmir	3037.8	2562.8	2402.9	2280.1
Punjab	15023.5	14674.9	14326.6	12355.8
Rajasthan	18165.4	17602.3	16950.0	16049.8
Uttar Pradesh	24903.1	24005.7	23214.0	21245.2
Uttarakhand	2399.2	2095.0	1935.8	1816.9
Chhattisgarh	5940.4	5782.7	5521.1	5098.9
Dadra & Nagar Haveli	1334.0	1309.7	1288.8	1246.9
Gujarat	24308.2	23240.7	22312.1	21041.9
Goa	631.3	569.7	526.2	500.7
Madhya Pradesh	15095.5	14821.6	13489.3	12161.2
Maharashtra	29452.0	28681.9	27874.8	26444.0
Andhra Pradesh	12638.3	12480.1	11921.3	11140.5
Karnataka	17264.8	16556.8	15667.8	14310.8
Kerala	4420.2	3898.3	3596.3	3453.7
Puducherry	479.7	433.3	407.6	384.4
Tamil Nadu	19806.4	18128.3	16885.2	15975.9
Telangana	15264.4	14783.5	14200.9	12579.7
Bihar	6774.8	6220.0	5873.2	5259.1
DVC	4060.6	3478.0	3293.9	3186.9
Jharkhand	1898.2	1693.1	1613.4	1495.1
Odisha	6713.5	6232.8	5310.2	4862.0
Sikkim	109.5	97.9	74.1	66.3
West Bengal	11758.7	9809.5	9332.3	8560.6
Arunachal Pradesh	162.3	141.7	136.5	125.4
Assam	2133.5	1996.5	1844.6	1637.6
Manipur	161.4	135.4	123.8	111.2
Meghalaya	298.6	279.3	253.0	230.6
Mizoram	116.0	98.8	87.8	79.2
Nagaland	163.2	150.5	131.4	117.3
Tripura	353.3	278.4	249.5	220.6
Sum Total	267582.4	248419.5	**240861.2**	221856.8
ALL INDIA Peak (SOLAR) Demand in 2023-24	**238160.4**			

State Wise Coincident Peak During Non-Solar Hours During FY 2023-24

State/UT	Maximum of Coincident Peak (top 5%) NON-SOLAR Hours	90th Percentile of Coincident Peak (top 5%) NON-SOLAR Hours	80th Percentile of Coincident Peak (top 5%) NON-SOLAR Hours	Average of Coincident Peak (top 5%) NON-SOLAR Hours
Chandigarh	375.9	347.9	339.5	307.6
Delhi	7122.8	6602.9	6414.8	5927.6
Haryana	12063.1	11102.7	10857.6	10255.6
Himachal Pradesh	1699.8	1476.9	1365.9	1219.5
Jammu & Kashmir	2873.8	2444.6	2360.7	2171.9
Punjab	14751.1	13129.0	12865.4	11532.6
Rajasthan	15387.8	14285.9	13849.6	13012.0
Uttar Pradesh	27557.4	26772.8	26300.6	25005.3
Uttarakhand	2343.9	2153.1	2100.7	1940.4
Chhattisgarh	5938.7	5498.2	5400.0	4936.5
Dadra & Nagar Haveli	1324.6	1286.5	1275.5	1244.5
Gujarat	21386.8	20305.3	19707.3	18418.1
Goa	660.3	605.9	577.3	532.7
Madhya Pradesh	14292.9	12376.0	11971.0	11282.0
Maharashtra	27176.8	26333.2	25685.7	24146.6
Andhra Pradesh	10938.4	10382.6	9906.0	9273.6
Karnataka	12506.5	10297.9	9848.8	9322.6
Kerala	4956.9	4261.4	4129.5	3859.9
Puducherry	508.9	468.9	450.3	422.4
Tamil Nadu	18285.2	17131.1	16687.9	15556.6
Telangana	12570.3	10156.9	9521.7	8731.3
Bihar	7270.1	6935.9	6774.8	6440.8
DVC	3870.1	3624.5	3467.3	3352.6
Jharkhand	1873.7	1694.1	1647.9	1523.5
Odisha	6741.3	5910.5	5687.9	5197.1
Sikkim	92.1	74.8	67.6	51.4
West Bengal	11326.5	10228.5	9852.8	9300.1
Arunachal Pradesh	172.3	156.5	148.7	133.0
Assam	2393.7	2225.5	2143.0	1909.9
Manipur	192.0	150.7	136.6	106.8
Meghalaya	321.2	281.0	268.6	226.2
Mizoram	116.3	102.6	96.2	75.4
Nagaland	163.5	151.7	147.6	121.8
Tripura	416.0	313.8	301.1	271.4
Sum Total	249670.8	229270.0	**222355.8**	207809.7
ALL INDIA Peak Demand (NON-SOLAR) in 2023-24	**216427**			

Annexure B

State Wise Coincident Peak During Solar Hours During FY 2022-23

State/UT	Maximum of Coincident Peak (top 5%) _SOLAR Hours	90th Percentile of Coincident Peak (top 5%) SOLAR Hours	80th Percentile of Coincident Peak (top 5%) SOLAR Hours	Average of Coincident Peak (top 5%) SOLAR Hours
Chandigarh	400.2	350.8	281.7	220.6
Delhi	6795.6	5400.1	5048.1	4352.7
Haryana	12543.3	9902.5	8187.5	7848.0
Himachal Pradesh	2024.8	1837.8	1781.8	1623.5
Jammu & Kashmir	2975.4	2815.7	2757.0	2459.2
Punjab	13741.3	10178.6	8768.9	8051.1
Rajasthan	17913.3	16274.8	15895.4	14768.7
Uttar Pradesh	22736.1	21465.5	19802.2	17445.0
Uttarakhand	2355.4	2063.4	1985.7	1791.8
Chhattisgarh	12232.7	5209.2	5114.4	4876.9
Dadra & Nagar Haveli	1379.2	1230.8	1217.3	1178.5
Gujarat	21506.4	20321.6	19512.2	18646.9
Goa	589.7	550.1	537.5	499.4
Madhya Pradesh	17090.6	16486.8	16176.8	13904.3
Maharashtra	31928.7	27872.8	27534.4	26635.2
Andhra Pradesh	12192.8	11650.8	11502.4	10817.3
Karnataka	15687.1	14950.4	14746.2	13200.2
Kerala	4172.4	3707.9	3412.8	3280.8
Puducherry	434.6	405.5	386.9	356.2
Tamil Nadu	17839.7	17146.4	16536.1	15498.5
Telangana	15084.1	14245.4	14071.6	12255.0
Bihar	5546.7	5126.4	4881.9	4245.4
DVC	3457.6	3334.0	3289.8	3192.7
Jharkhand	1600.9	1486.6	1446.6	1359.8
Odisha	6223.0	5629.1	5211.3	4577.0
Sikkim	118.8	105.6	100.2	86.7
West Bengal	9723.8	8573.4	7888.7	6934.8
Arunachal Pradesh	142.4	120.6	113.8	101.5
Assam	1540.3	1540.3	1521.0	1226.8
Manipur	202.1	152.9	142.3	120.5
Meghalaya	345.3	311.0	298.6	259.0
Mizoram	111.0	97.0	90.3	79.3
Nagaland	134.4	111.4	101.4	91.6
Tripura	214.2	190.3	190.3	174.5
Sum Total	260984.1	230845.5	**220533.1**	202159.6
ALL INDIA Peak (SOLAR) Demand in 2022-23	**210443.2**			

State Wise Coincident Peak During Non-Solar Hours During FY 2022-23

State/UT	Maximum of Coincident Peak (top 5%) NON-SOLAR Hours	90th Percentile of Coincident Peak (top 5%) NON-SOLAR Hours	80th Percentile of Coincident Peak (top 5%) NON-SOLAR Hours	Average of Coincident Peak (top 5%) NON-SOLAR Hours
Chandigarh	362.8	327.8	315.0	277.4
Delhi	7046.0	6277.3	5845.8	4854.7
Haryana	11757.6	9423.8	9132.5	8330.2
Himachal Pradesh	1738.6	1476.0	1425.3	1299.9
Jammu & Kashmir	2762.2	2477.4	2392.0	2146.8
Punjab	13768.4	11729.4	10228.7	9272.4
Rajasthan	13951.5	12839.0	12645.5	11668.5
Uttar Pradesh	26309.7	25098.2	24616.8	22687.2
Uttarakhand	2437.8	2236.6	2151.3	1953.1
Chhattisgarh	12012.1	4951.5	4714.6	4480.4
Dadra & Nagar Haveli	1267.1	1200.1	1188.4	1116.9
Gujarat	19138.8	18429.6	18171.6	17544.6
Goa	606.4	554.6	544.3	499.0
Madhya Pradesh	13663.1	11560.3	11306.1	10652.4
Maharashtra	26259.4	25152.8	24798.4	23538.4
Andhra Pradesh	9703.9	9161.1	8867.7	8375.2
Karnataka	11197.1	9951.0	9018.1	8170.7
Kerala	4464.9	4066.3	3945.3	3512.1
Puducherry	478.9	449.3	439.6	414.8
Tamil Nadu	17009.0	16143.8	15881.8	14818.4
Telangana	10172.5	8406.9	8176.5	7545.9
Bihar	6354.1	6048.0	5937.9	5515.9
DVC	3510.8	3356.0	3311.1	3203.7
Jharkhand	1779.2	1458.2	1409.5	1327.0
Odisha	6334.4	5792.2	5663.2	5350.7
Sikkim	109.0	89.9	81.4	61.0
West Bengal	9597.8	8905.3	8701.2	8051.7
Arunachal Pradesh	154.8	130.7	123.9	106.5
Assam	2269.6	1793.2	1540.3	1554.7
Manipur	193.2	155.4	140.4	108.0
Meghalaya	378.4	315.7	300.1	257.3
Mizoram	127.8	111.0	104.5	84.5
Nagaland	149.0	124.5	116.9	97.5
Tripura	309.7	275.1	253.2	213.3
Sum Total	237375.4	210468	**203489**	189090.6
ALL INDIA Peak Demand (NON-SOLAR) in 2022-23	**198589.1**			

Annexure C

Capacity Credit of Solar and Wind (State-wise) (Solar and Non-Solar Hours)

Solar

State	Capacity Credit (p.u.) (Solar Hours)
GUJARAT	0.56
MAHARASHTRA	0.56
KARNATAKA	0.54
BIHAR	0.48
CHHATTISGARH	0.57
HIMACHAL PRADESH	0.49
HARYANA	0.49
KERALA	0.46
MANIPUR	0.46
MEGHALAYA	0.33
MIZORAM	0.47
NAGALAND	0.32
DELHI	0.51
ODISHA	0.48
GOA	0.55
ARUNACHAL PRADESH	0.25
PUNJAB	0.47
RAJASTHAN	0.57
JHARKHAND	0.57
MADHYA PRADESH	0.54
SIKKIM	0.35
TELANGANA	0.55
ANDHRA PRADESH	0.53
TAMIL NADU	0.53
TRIPURA	0.42
UTTAR PRADESH	0.49
UTTARAKHAND	0.57
WEST BENGAL	0.51
ASSAM	0.42

Wind

State	Capacity Credit (p.u.) (Solar Hours)	Capacity Credit (p.u.) (Non-Solar Hours)
KARNATAKA	0.103	0.28
TAMILNADU	0.126	0.28
ANDHRA PRADESH	0.087	0.32
GUJARAT	0.129	0.25
MADHYA PRADESH	0.098	0.23

Please Note that the capacity credit of Solar generators during non-solar hours may be considered as 0

Annexure D

K-means Clustering Algorithm for Demand & VRE

The following steps are taken for the k means clustering algorithm to determine the critical days in a month.

1. Determine the number of clusters to be formed in a month (in this case, 3 clusters to be formed, namely High, Medium, and Low).

For Demand clustering

2. Randomly assign Clusters to different days in the month—Ex (1st April- Cluster 1, 2nd April - Cluster 2, and so on). A total of 36 (3*12) clusters will be formed.
3. Determine each cluster's average values (24 values for 24 hours) in a month.
4. In the 1st iteration, check the distance of 1st April from 3 clusters formed in April (Distance between Cluster 1 to each value of 1st April and so on). Re-assign the 1st of April to the cluster that is closest to it.
5. For 2nd April, the cluster averages will change due to the reassignment of a cluster on 1st April. Repeat the process for all 365 days of the year.
6. Calculate the number of days in each of the clusters.
7. Repeat step 4 till the number of days in each cluster becomes constant. (Typically, 3 to 4 iterations are required.)
8. After the clusters are fixed, check which of the clusters' average demand (average of 24 hours) is the highest in a month. Assign the high-demand cluster to that cluster. Similarly,, identify the average and low demand clusters for each month.

For VRE clustering

Add Solar and Wind generation to calculate VRE generation.

Repeat Steps 2 to 8, which is similar to demand generation.

9. After the Demand & RE clusters are formed, identify the High Demand-High RE and High Demand -Low RE days using the pivot table. Calculate the number of days in each of such clusters.

Annexure E

Capacity Credit of Solar and Wind (State-wise) (Critical Days)

Solar

State	Capacity Credit (p.u.) (Solar)
GUJARAT	0.46
MAHARASHTRA	0.45
KARNATAKA	0.46
BIHAR	0.41
CHHATTISGARH	0.44
HIMACHAL PRADESH	0.37
HARYANA	0.4
KERALA	0.42
MANIPUR	0.41
MEGHALAYA	0.3
MIZORAM	0.41
NAGALAND	0.32
DELHI	0.4
ODISHA	0.4
GOA	0.45
ARUNACHAL PRADESH	0.29
PUNJAB	0.39
RAJASTHAN	0.46
JHARKHAND	0.43
MADHYA PRADESH	0.43
SIKKIM	0.31
TELANGANA	0.43
ANDHRA PRADESH	0.42
TAMIL NADU	0.46
TRIPURA	0.35
UTTAR PRADESH	0.42
UTTARAKHAND	0.46
WEST BENGAL	0.42
ASSAM	0.35

Wind

State	Capacity Credit (p.u.) (Solar Hours)	Capacity Credit (p.u.) (Non-Solar Hours)
KARNATAKA	0.09	0.17
TAMILNADU	0.08	0.07
ANDHRA PRADESH	0.09	0.14
GUJARAT	0.13	0.21
MADHYA PRADESH	0.08	0.19

Please Note that the capacity credit of Solar generators during non-solar hours may be considered as 0