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Power Chronicle

Capacity Credit for Resource Adequacy, Demand Response and Carbon Credit Trading Mechanism

Editorial

The regulatory framework for Resource Adequacy by the Discoms, while proposing hourly, block-wise demand forecasting and resource adequacy planning, should add the minimum requirements and emphasize a framework for data collection on a 15-min block basis. This would not only ensure that a comparative assessment of hourly versus 15-min block-wise, a Resource Adequacy planning may be undertaken while also ensuring that the distribution licenses as well as the SLDCs, make consulted effort for collection and archival of 15-min block wise data. The methodological approach should be guided by various factors, including the availability of data and the specific techno-economic parameters that influence the profile and growth of electricity demand.

Learning from developments in the Renewable Energy Certificates market should guide the evolutionary journey of the market for carbon credit. Division of market liquidity, due to separation in category of certificates, and economic anomalies in fixing the floor price for the certificates are among the key shortcomings of the REC market. The market for carbon credit should not be segregated into different market segments. Design of appropriate targets for reduction in emission intensity and a robust compliance should ideally negate the need of setting the price for the carbon credit certificates.

Growing share of RE sources places operational burden on the thermal generating units in terms of higher fuel consumption while operating at part load and higher maintenance requirement of the generation units. Operationalization of the regulatory framework for compensation should adhere to key regulatory principles. For example, the framework for determining compensation components for ISGS provide for normative secondary fuel consumption. The compensation procedure should be based on this normative benchmark, rather than actual fuel consumption, it would incur significant verification costs and create information asymmetry.

Uncertainty in long-term forecasts of demand and generation capacity, particularly from RE sources, may lead to short-term supply shortages. Furthermore, few long-term power procurements entailing capacity charges could be avoided if sufficient demand response measures effectively reduce the demand-supply gap for short periods throughout the year.

The design of demand response programs must consider the relative economics of demand curtailment for enrolled consumers, as well as the price elasticity of their demand. An effective mechanism to measure and monitor the demand response against a baseline remains critical to the success of such programs. Otherwise, the discoms may end up paying for ghost demand response without adequate measures by the enrolled consumers. Pilot demand response programs and analytics of the historical demand and profile of the targeted consumer categories would provide greater insights for designing effective dynamic programs across the country.

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Keywords: Resource Adequacy, Capacity Credit, Coincident Peak, Demand Side Management, Demand Response, Environmental Compliance, Carbon Credit Certificates, Carbon Credit Trading Scheme, Banking, Governance Framework, Market Monitoring and Long-term Demand Forecasting.

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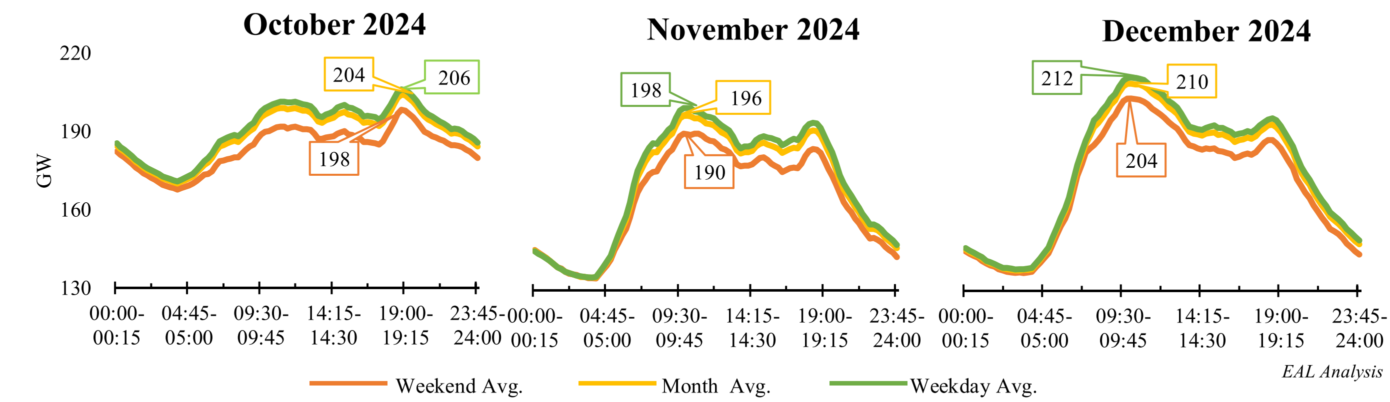
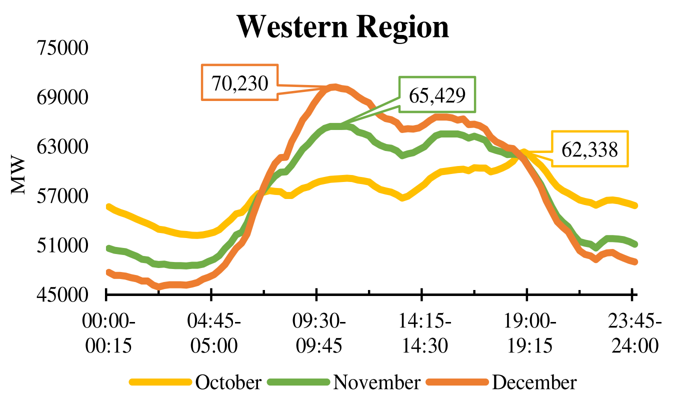
Power System Overview & Analysis

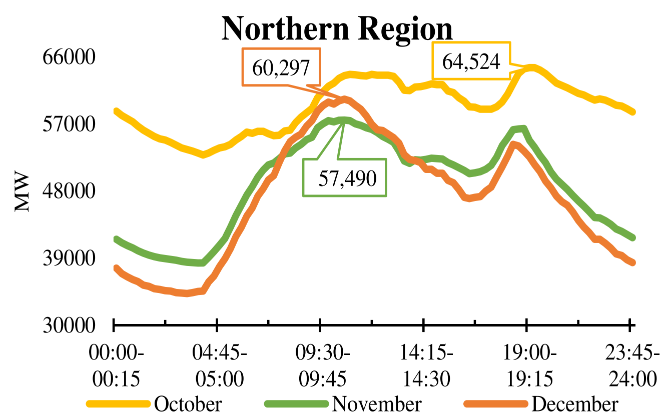
All India Demand Met Profile

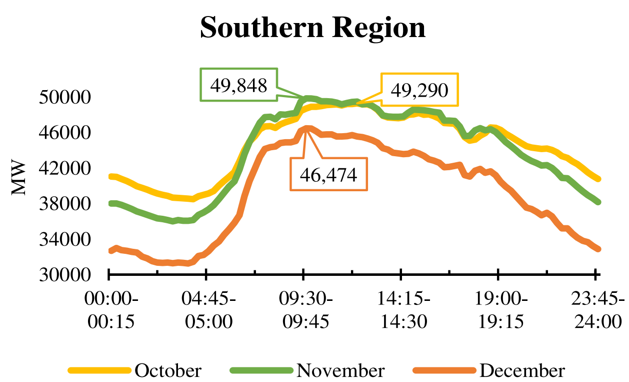


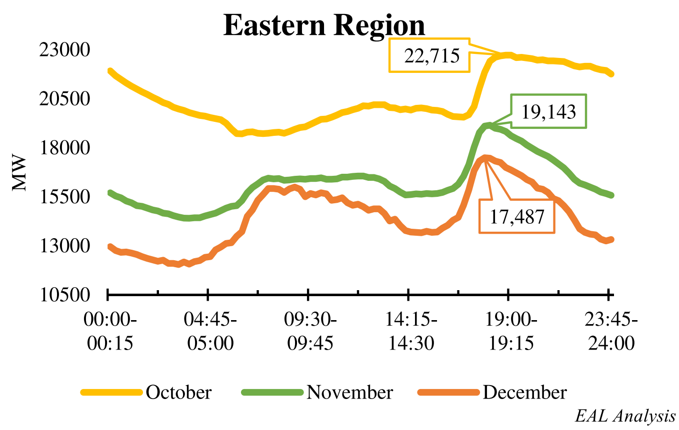
From October to December quarter, all India peak demand reached 212 GW (10:00 - 10:15) on 13th December 2024, about 4.28% lower than the previous year's peak demand recorded at 221.5 GW (12:15 - 12:30) on 10th October 2023, during the same quarter.

Region-wise Demand Met Profile

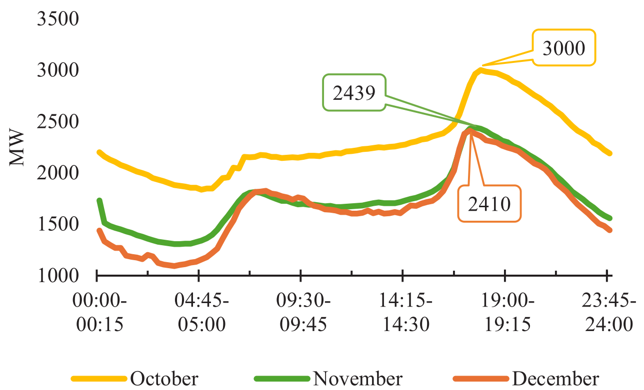








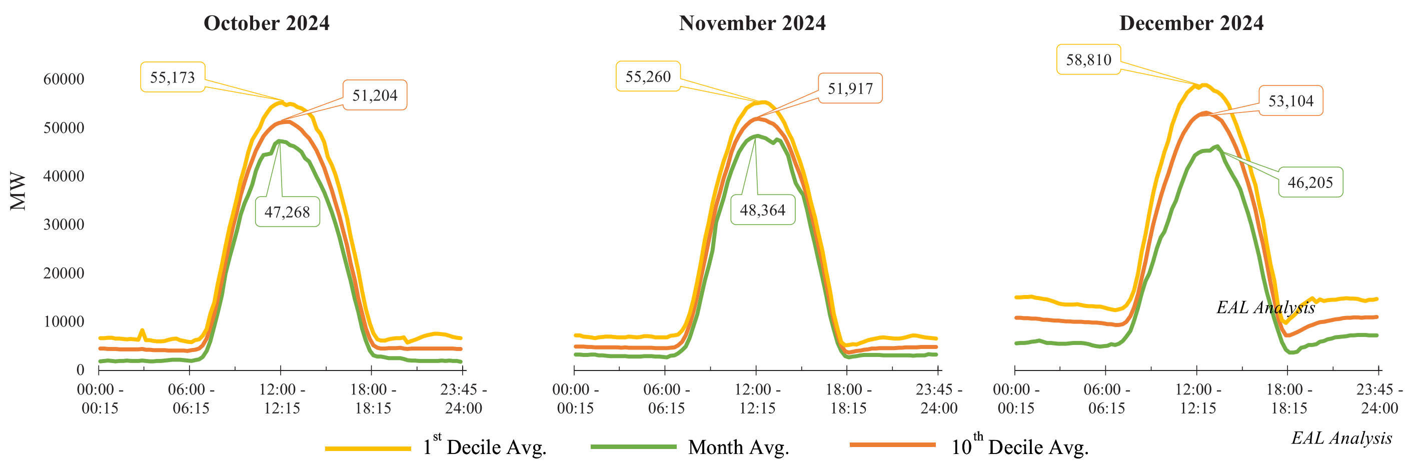
North Eastern Region



- Significant increase in demand can be observed for Eastern and Northern region from 17:00 to 18:30 and North-Eastern region from 16:30 to 17:45 hrs in this quarter.
- Gradual increase in demand can be observed for North Eastern region from 17:00 to 18:45 hrs in all the three months respectively.
- Average demand is found to be higher for Western region as compared to the other regions in the month of December.

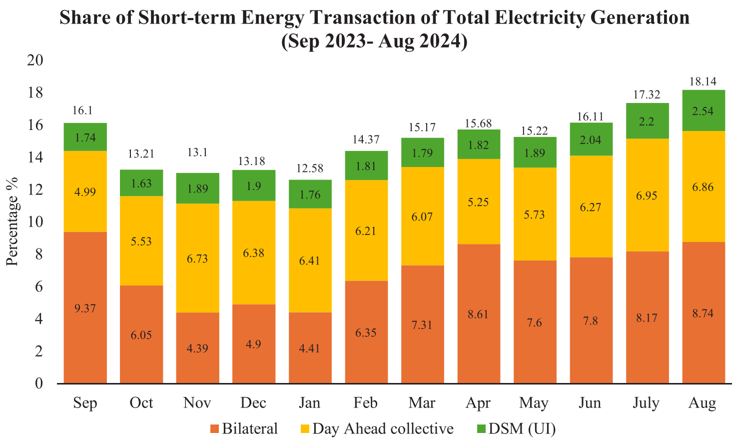
Demand and generation profiles at National, Regional and State-level can be accessed on EAL's web portal.

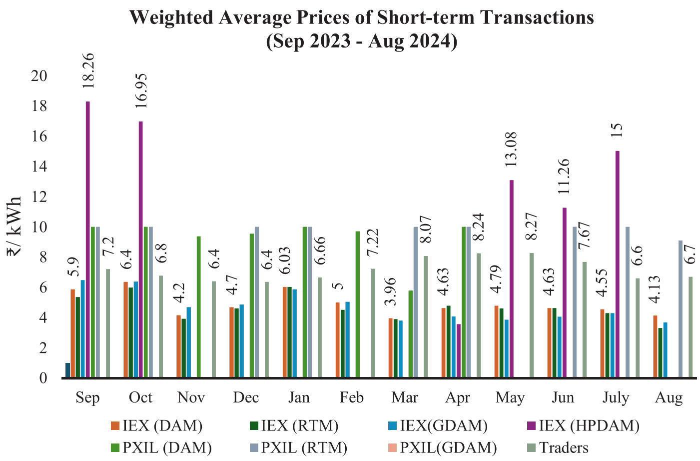
All India Renewable Energy (RE) Generation Profile



All India peak RE generation reached 58.81 GW (12:45-01:00) on 10th December, 2024, about 17.90% higher than the previous year's peak of 49.88 GW (12:45 - 13:00) on 06th October, 2023.

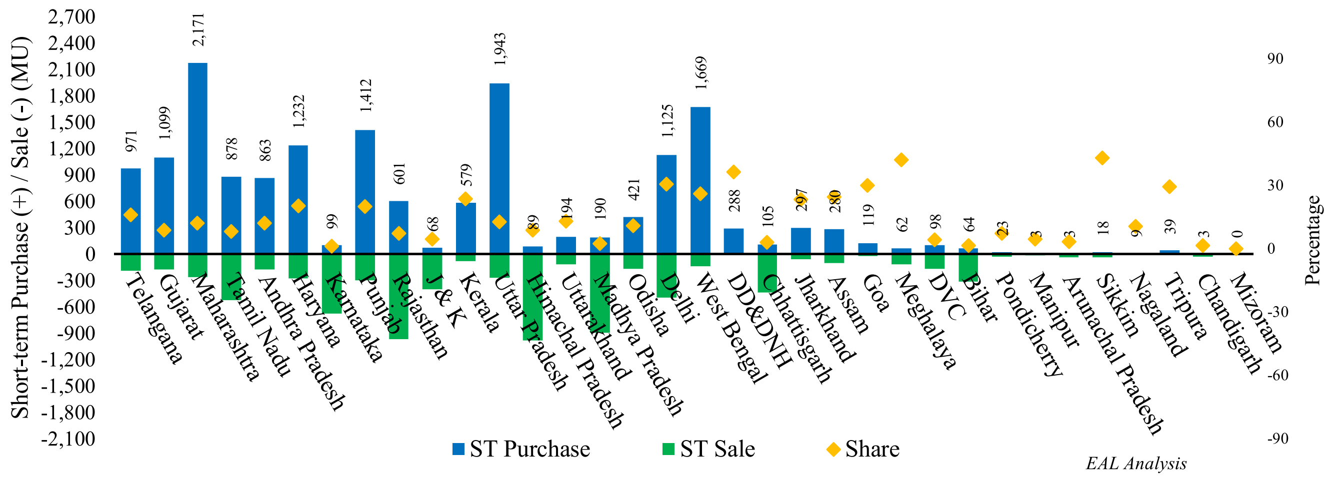
Short-term Energy Transactions





Monthly Power Purchase and Sale Quantum through Power Exchange across States

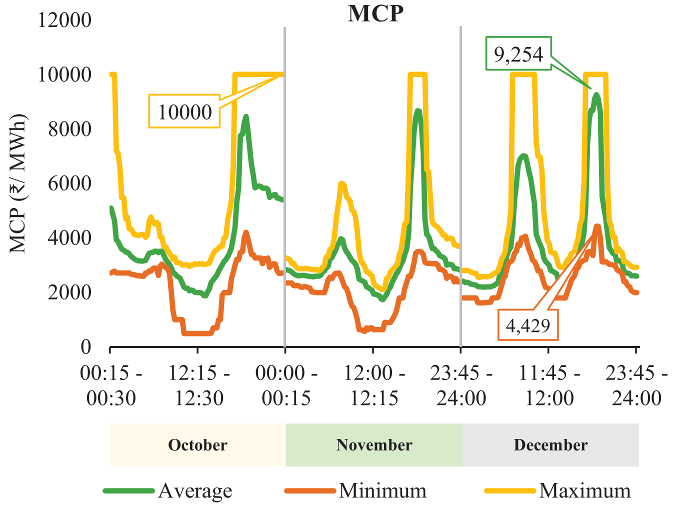
ST Energy Sale, ST Energy Purchase and share of ST Purchase in Total Energy Supplied (Aug 2024)



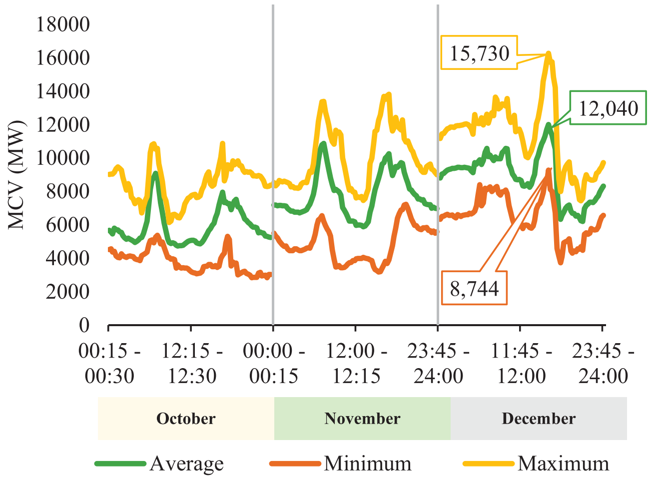
Power Market Overview & Analysis

DAM - Market Clearing Price (MCP) & Market Clearing Volume (MCV)

DAM Monthly Average, Maximum & Minimum MCP

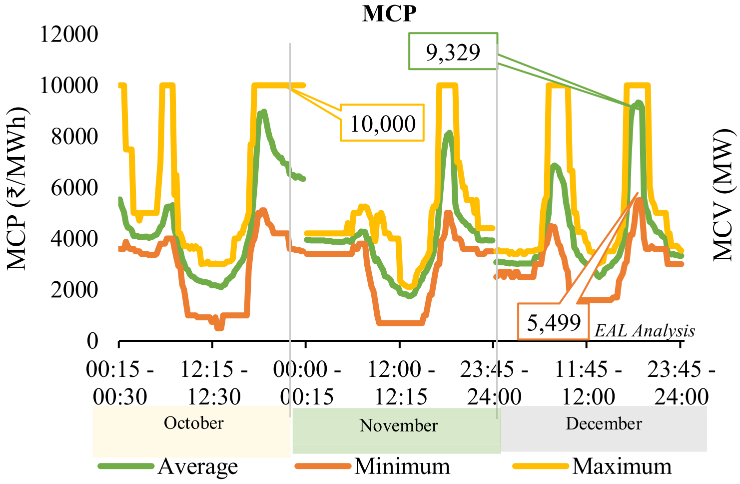


DAM Monthly Average, Maximum & Minimum MCV

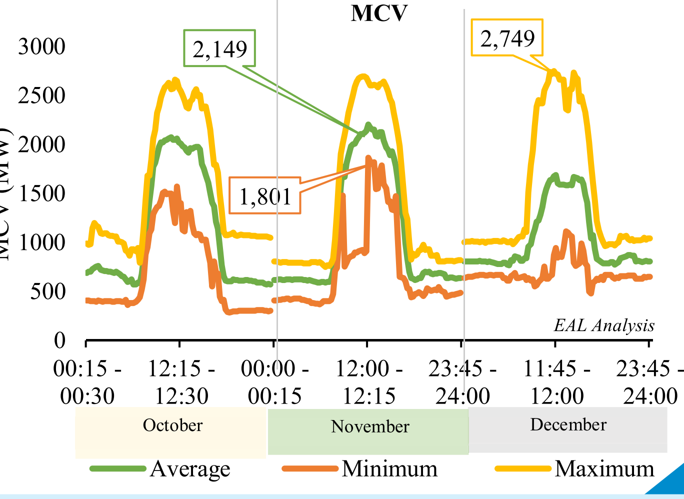


G-DAM - Market Clearing Price (MCP) & Market Clearing Volume (MCV)

G-DAM Monthly Average, Maximum & Minimum MCP

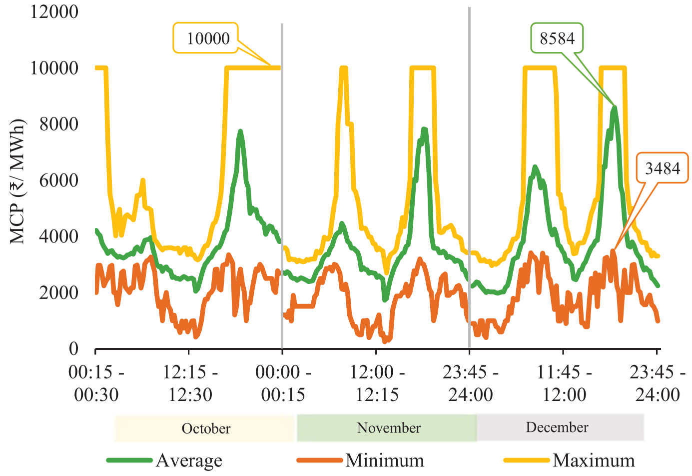


G-DAM Monthly Average, Maximum & Minimum MCV

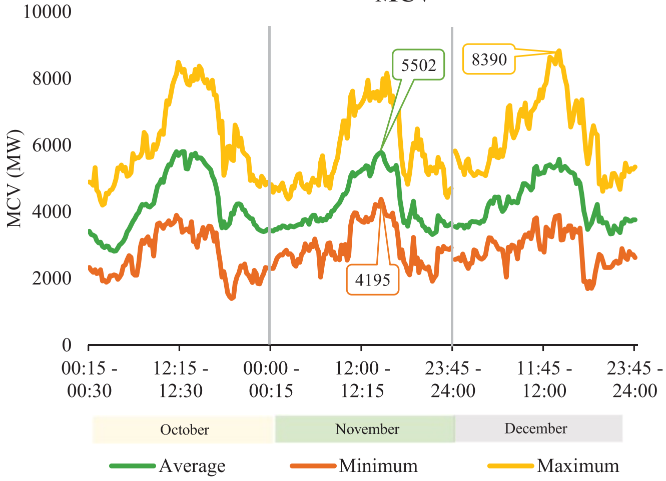


RTM -Market Clearing Price (MCP) & Market Clearing Volume (MCV)

RTM Monthly Average, Maximum & Minimum MCP

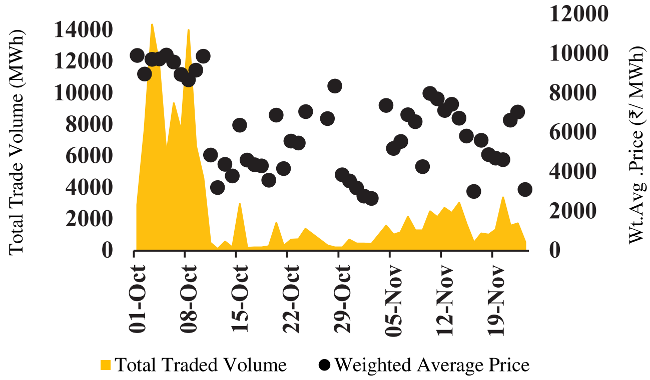


RTM Monthly Average, Maximum & Minimum MCV



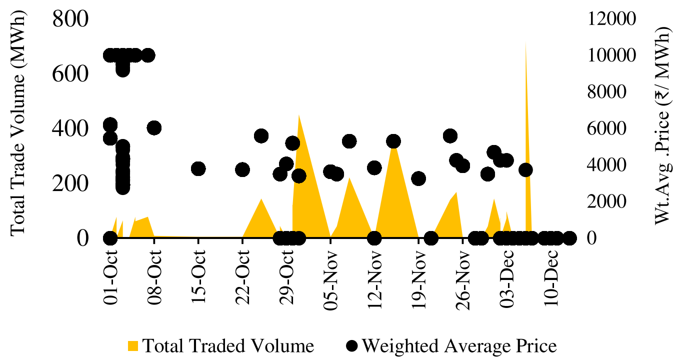
Term-Ahead Market (TAM)

Daily Day-Ahead Contigency(Oct-Dec 2024)



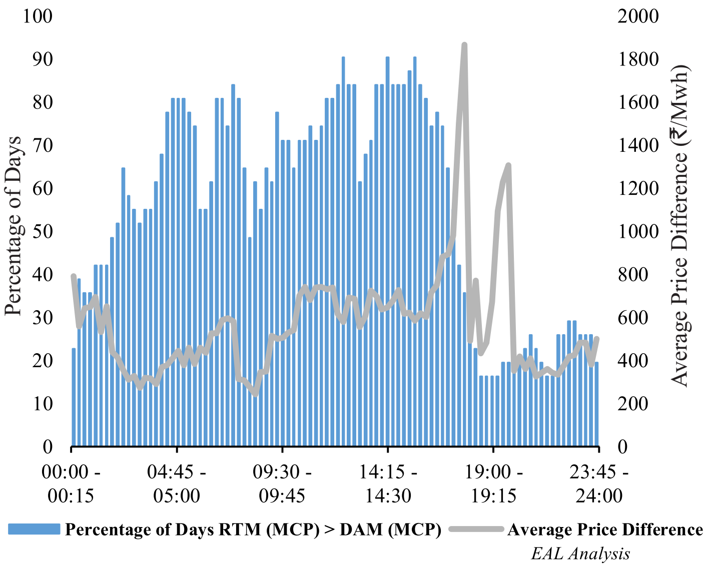
Green Term-Ahead Market (G-TAM)

Daily Trades(Oct-Dec 2024)

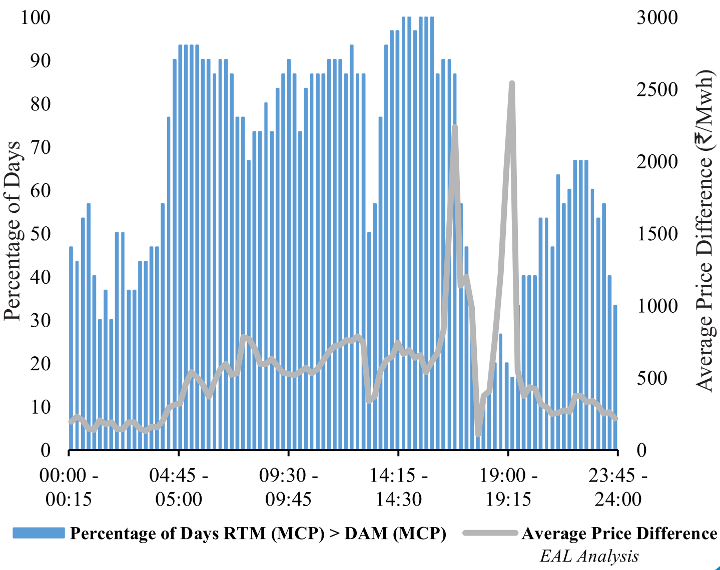


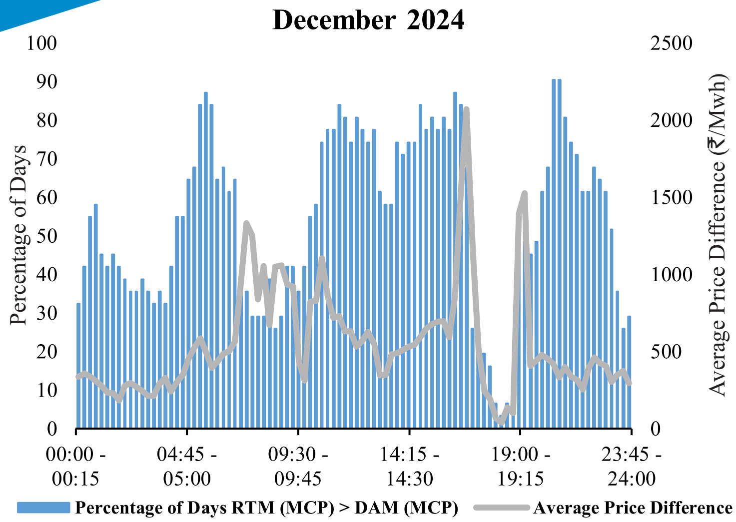
Price Difference between RTM & DAM

October 2024



November 2024

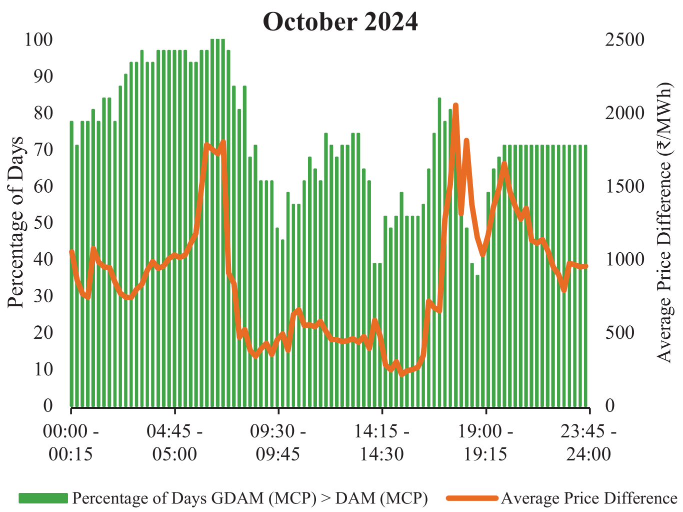


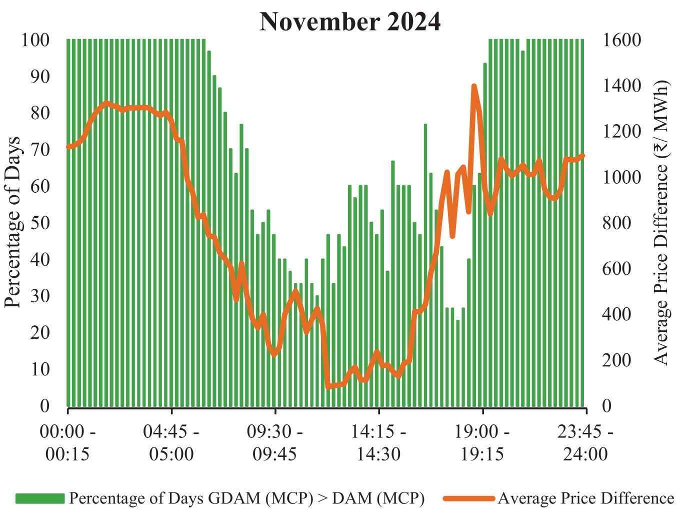


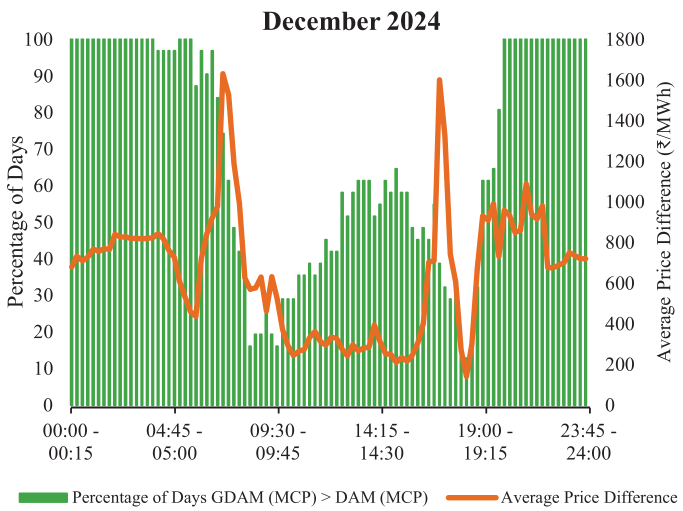
EAL Analysis

- The analysis is based on comparison between the average price difference of RTM and DAM, when MCP of RTM is greater than DAM for the Third quarter of year 2024-25.
- The graph shows the percentage of days, price for RTM is greater than DAM on the primary axis and the average price difference between the two on secondary axis.
- The maximum price difference between RTM and DAM has been observed between 14:00-14:15 and 15:30-15:45 blocks for the month of November 2024.
- The average price difference between RTM and DAM is ₹ 0.54/kWh for the quarter.

Price Difference b/w G-DAM & DAM







EAL Analysis

- The analysis is based on comparison between the average price difference of G-DAM and DAM, when MCP of G-DAM is greater than DAM for the Third quarter of year 2024-25.
- The graph shows the percentage of days, price for G-DAM is greater than DAM on the primary axis and the average price difference between the two on secondary axis.
- The maximum price difference between G-DAM and DAM has been observed between 04:30- 04:45 and 06:00- 06:15 blocks for the month of October, 2024.
- The average price difference between G-DAM and DAM is observed to be ₹ 0.75/kWh for this quarter"

Regulatory & Policy Perspective

Opinion on AERC (Framework for Resource Adequacy) Regulations, 2024 [Draft] Cite

Assam Electricity Regulatory Commission notified draft regulations on Framework for Resource Adequacy (RA) on 06th September, 2024. The key highlights of this draft document are mentioned below:

- **Objective:** The framework emphasizes the need for distribution licensees to optimize power procurement planning to support RE integration and maintain system reliability. Additionally, the draft regulation states that discoms must maintain a minimum of 70% of their long-term contracts, 20% from medium-term, and the remaining from short-term contracts. During the power procurement planning, discoms must consider the impact of RPO, demand side management, energy efficiency programs and energy conversation programs. Furthermore, the State Load Despatch Centre and discoms are directed to provide 10-year demand forecasts to relevant government agencies for conducting Resource Adequacy Planning (RAP).

EAL Opinion

- **The Role of RA Framework:** Utilities in India are facing the challenge of reliably meeting peak demand. To tackle this, a combination of adequate power supply, a demand response framework, and the sharing of power across states and regions is crucial. The key objective of the RA framework is to ensure availability of adequacy capacity to meet the forecasted demand, ensuring system security and reliability. Power procurement costs are a critical factor in the RA analysis. Since power procurement plans and contracts are typically long-term, they need to be developed well in advance, relying on dependable forecasts.

  With the experience of EAL in conducting long-term demand forecasting and power procurement planning for the states of Uttar Pradesh and Chhattisgarh, the necessity for a robust regulatory framework for the same was emphasised. This culminated into publication of a book titled "Regulatory Framework for Long-term Demand Forecasting and Power Procurement"[1] And opinion on CEA's resource adequacy guidelines[2] and, draft regulations by ERCs[3],[4] would provide further insights into the design of regulations and implementation thereof.

- **Necessity of 15-Minute Time Block-Wise Demand Forecast:** Draft clause 6.1 states that *"It shall entail hourly assessment and forecasting of demand within the distribution area of the Distribution Licensee for multiple horizons….."*

  Draft clause 7.2 states that *"For the purpose of ascertaining hourly load profile and for assessment of contribution of various consumer categories to peak demand, load research analysis shall be conducted and influence of demand….."(emphasis added)*

  Draft clause 7.1 and 7.4 states that *"mentions hourly, or sub-hourly assessment and forecasting of demand within the distribution area."*

  Draft clause 10.2(a) and 10.2(b) states that *"For each year, the hourly recorded Gross Load for 8760 hours (or time-block) shall be arranged in descending order. And for each hour, the Net Load is calculated by subtracting the actual wind or solar generation corresponding to that load for 8760 hours (or time-block)"…*

Suggested Citation : Singh, A. (ed.). (2024), Opinion on AERC (Framework for Resource Adequacy) Regulations, 2024 [Draft], In Power Chronicle (Vol. 07, Issue 03, pp. 7-10), Energy Analytics Lab (EAL), Indian Institute of Technology Kanpur, https://eal.iitk.ac.in/assets/docs/power_chronicle_vol_7_issue_3.pdf

[1] Singh, A. (ed.). (2019), Regulatory Framework for Long-term Demand Forecasting and Power Procurement Planning, Centre for Energy Regulation (CER), Indian Institute of Technology Kanpur, Book, https://cer.iitk.ac.in/assets/downloads/CER_Monograph.pdf

[2] Singh, A. (ed.). (2022), Opinion on CEA (Resource Adequacy Framework for India) Regulations, 2022 [Draft], In Power Chronicle (Vol. 5, Issue 03, pp. 6-11), Energy Analytics Lab (EAL), Indian Institute of Technology Kanpur, https://eal.iitk.ac.in/assets/docs/power_chronicle_vol_5_issue_3.pdf

[3] Singh, A. (ed.). (2022), Opinion on MPERC (Power Purchase and Procurement Process) Regulations [Draft], Revision-II, 2022 (RG-19(2) of 2022), In Regulatory Insight (Vol. 05, Issue 02, pp. 2-3), Centre for Energy Regulation (CER), Indian Institute of Technology Kanpur. https://cer.iitk.ac.in/odf_assets/upload_files/blog/Revision_2_2022_Power_Procurement_Draft_Regulation.pdf

[4] Singh, A. (ed.). (2021), Opinion on APERC (Terms and Conditions for Short-term Procurement/sale of power) Regulation, 2021 [Draft], In Regulatory Insight, (Vol. 04, Issue 03, pp. 7-10), Centre for Energy Regulation (CER), Indian Institute of Technology Kanpur. https://cer.iitk.ac.in/odf_assets/upload_files/Draft_APERC_Terms_and_Conditions_for_short_term_procurement_sale_of_power_Regulation_2021.pdf

The terms "hourly","sub-hourly" and time block are used interchangeably in several instances. It's recommended to maintain consistent terminology throughout the draft for better understanding.

Scheduling as well as market operation are undertaken on a 15-minute time block basis. With increasing share of variable renewable energy, forecasting as well as power procurement planning for shorter time granularity gains further relevance. Emphasizing block-wise planning would not only enhance forecast accuracy but also improve power procurement planning for the discom. Even if the final regulations mandate hourly forecasts and planning for RA thereof, the Commission should mandate compiling and archival of 15-minute time block data and its availability in public domain so as to assist research and development of better forecasting and planning tools in future.

- **Techno-Economic Parameters:** Draft clause 6.9 states that *"The Distribution Licensee may modify the load obtained ….... separate trajectory should be developed for each customer category."*

  Demand Side Management (DSM) efforts, including load management actions taken by discoms, have significantly impacted historical load profiles. Draft clause 6.9(d) highlights the importance of considering past DSM practices. However, in the absence of historical data on DSM practices, it is challenging to incorporate these insights into future predictions. The discoms should begin compilation of granular data on various DSM actions for its utilisation in future RA planning exercises.Additionally, visibility of behind the meter generation from solar rooftop is vital for reliable demand forecast in future. Integration of data from smart metering systems will also yield important insights into customer demand behaviour and energy usage trends, assisting more reliable estimate of granular demand forecasts.[5]

- **Role of Deviation Settlement Mechanism in Load Forecast:** Draft clause 6.9(g) states that *"Deviation Settlement Mechanism"* is mentioned as part of the forecasting process. It is a real-time mechanism designed to address deviations between scheduled and actual generation and consumption. It cannot be predicted or forecasted in advance it challenges for long-term planning. Additionally, tightening of frequency band and introduction of ancillary services market is expected to mitigate its impact in future. As a result, Deviation Settlement Mechanism cannot be not be used as a factor affecting long-term demand forecasting.

- **Changes in Specific Energy Consumption:** Draft clause 6.9(j) states that the *"Changes in specific energy consumption"* is to be considered as a factor for demand forecasting. Demand forecasting is an exercise to predict the same. It seems that this is in the context of partial end of use approach to load forecast that uses expected change in specific energy consumption. In the context of econometric forecast, this is related to the output variable. How should and output variable be used as an input variable while using such an approach? Differentiation for the same should be incorporated. Additionally, there is no clarification on how the necessary data for these changes will be collected from a bottom up approach.

- **Load Forecast Given In MWh:** Draft clause 6.12 states that *"The summation of energy forecast (MWh) for various consumer categories upon adjusting for captive, prosumer, and open access load forecast, as obtained as per Draft clauses 6.5 to clause 6.11, as the case may be, shall be the load forecast for the Distribution Licensee."*

  Load forecasts and energy forecasts should be differentiated in units as they are different concepts, load forecast should be expressed in megawatts (MW). However, the Draft clause 6.13 and 6.14 mention load forecast in megawatt-hours (MWh). The same be corrected with appropriate context differentiating the two given clause.

- **Regulatory Framework for Grid Management and Environmental Compliance:** Draft clause 9.4 states that *"Constraints such as penalties for unmet demand, forced outages, spinning reserve requirements, and system **emission limits** as defined in State and Central electricity grid codes, planning criteria of CEA and **emission norms** specified by the Ministry of Environment and Forest shall be identified and enlisted."(emphasis added)*

  This regulation's emphasis on identifying constraints like penalties for unmet demand, forced outages, spinning reserve requirements, and emission limits is crucial for effective grid management. Aligning with State and Central Grid codes, CEA planning criteria, and Ministry of Environment, Forest and Climate Change norms ensures a

[5] Singh, A. (ed.). (2024), Opinion on OERC (Framework for Resource Adequacy), Regulations, 2024 [Draft], In Power Chronicle (Vol 07, Issue 2, pp. 7-10), Energy Analytics Lab (EAL), Indian Institute of Technology Kanpur. https://eal.iitk.ac.in/assets/docs/power_chronicle_vol_7_issue_2.pdf

comprehensive framework for reliability and environmental compliance, supporting better planning and operational decisions in the energy sector.

Emissions limits are not specified, and would not likely be, as a part of state or central grid code. Such emission limits may be specified for an individual unit or sector as a whole, and may likely be an outcome of India's commitments to limits emission of greenhouse gases (GHGs) if implemented in future. The emission norms (concentration), for example in terms of PM, SOx or NOx are specified for the respective generating units and also depend on the quality of fuel used.

Table1: Emissions limits for Thermal Power Plants in India[6]

Date of Installation	Particulate Matter (PM)	SO_2	NO_x	Mercury (Hg)
Before 31-12-2003	100 mg/Nm^3	600 mg/Nm^3 for <500MW 200 mg/Nm^3 for >=500MW	600 mg/Nm^3	0.03 mg/Nm^3 for >=500MW
After 01-01-2004 & Up to 31-12-2016	50 mg/Nm^3	600 mg/Nm^3 for <500MW 200 mg/Nm^3 for >=500MW	300 mg/Nm^3	0.03 mg/Nm^3
On or after 01-01-2017	30 mg/Nm^3	100 mg/Nm^3	100 mg/Nm^3	0.03 mg/Nm^3

- **Evaluation of Power Exchange Products for Resource Adequacy Requirements (RAR):** Draft clause 11.9 states that *"Provided that power procurement through Day-Ahead Market (DAM), shall not be considered towards the contribution for meeting RAR"*.

Power exchanges offer a range of products with different maturities for power procurement. While near-term products like RTM and DAM may not guarantee availability of power in advance, some of the TAM products allow procurement choices up to 3 months ahead. The RA framework permits ST products to be procured by a (discom) either in the previous year or within the current year. A parity in line with ST power procurement through traders should be offered for such PX products as well.

Given the liquidity of some TAM products, it may be feasible to procure for at least the first six months of the following FY, which are typically high-demand months. Since T-GNA is available for up to 11 months, at the time of submitting the RA plan in September/October, the discom may be able to meet some of its needs through these market products. Additionally, according to draft clause 14.8, the role of procurement via the DEEP and PUSHP portals would only be relevant if there is a sufficient procurement horizon, meaning it should exclude any procurement planned for less than three months in advance, with a minimum period to be specified by the Commission.

- **Procurement Planning:** Draft clause 15.6 states that *"GRIDCO shall also demonstrate to the Commission 100% tie-up for the first year and a minimum 90% tie-up for the second year (on rolling basis) to meet the requirement of their contribution towards meeting national peak. Only resources with Long / Medium /Short-Term contracts shall be considered to contribute to the RA"*.

Given the significant time required to establish new capacity, achieving 100% long-term capacity tie-up in the initial years, and that too across all discoms across the nation, may not be feasible. A phased approach could be utilized for the intial three years year following the issue of these regulation, gradually increasing capacity adequacy requirements to 95%, 98%, and ultimately 100%. A mandate to ensure 100% capacity procurement could lead the power market to become a sellers' market providing significant market power to generators with merchant capacity at hand. This may force discoms to enter into less favourable short-term or medium-term contracts. Thus, it's essential that the rollout of the RA plan allows reasonable time for utilities to ensure compliance during the initial three years. This also underscores the significance of demand response, which has a much shorter gestation period and should be considered as a tangible means to ensure resource adequacy.[5]

Moreover, securing capacity for short-term (ST) needs for the upcoming FY by the end of November of the current year is not technically feasible due to the lack of ST contracts that can meet demand more than 12 months in advance. It should also be permissible to contract this capacity through the 11-month TAM products once available. This may necessitate planning for short-term contracts within the year of RA planning.

Ensuring Adequate Transmission in Resource Adequacy Planning: Draft Clause 2.1 states that *"The objective of these Regulations is to enable the implementation of Resource Adequacy framework by outlining a mechanism for planning of generation, **transmission** resources for reliably meeting the projected demand in compliance with specified reliability standards for serving the load with an optimum generation mix."*

Need for suitable transmission facilities becomes a key constraint in RA exercise. While the draft document mention this as one of its objectives, it doesn't not seem to translate into actionable steps. The draft regulation should ideally lead to more focused planning of generation at the state level or focusing on an optimal generation mix promoting sustainability with improve reliability. The resultant transmission constraints should be identified and addressed through the transmission planning exercise undertaken in coordination with the National Electricity Plan.

Opinion on CERC (Terms and Conditions for Purchase and Sale of Carbon Credit Certificates) Regulations, 2024[Draft]

Cite

Central Electricity Regulatory Commission issued draft Regulation on Terms and Conditions for Purchase and Sale of Carbon Credit Certificates on 13th November, 2024.

Objective: These draft regulations create a framework for trading of Carbon Credit Certificates (CCCs) to facilitate a reliable and regulated carbon market, encourage participation across diverse sectors, and support India's climate commitments. The regulations will also facilitate the exchange of CCCs for obligated and non-obligated entities on Power Exchanges. The key aspects for governing the trade of certificates are:

- **Registry:** The Grid Controller of India will function as the Registry for the exchange of CCCs and establish the necessary framework.
- **Functions of Administrator:** The Bureau of Energy Efficiency (BEE) will act as the Administrator, formulating detailed procedures, providing assistance to the CERC, disseminating market information and ensuring transparent exchange of CCCs.
- **Category of Certificates:** CCCs are categorized for obligated and non-obligated entities and the CERC will permit Power Exchanges to introduce such categories.
- **Pricing of Certificates:** The market price of CCCs is discovered through bidding on Power Exchanges, within a floor price and forbearance price approved by the CERC.
- **Banking and Extinguishment of CCCs:** The procedures for banking and extinguishment of CCCs are specified in the detailed procedures of the Carbon Credit Trading Scheme, 2023.

EAL Opinion

Definition of 'Extinguishment': Draft clause 2.1 (c) states that *"Banking and Extinguishment of CCCs means banking and **Extinguishment** of CCC as provided in the Detailed Procedure for Compliance Mechanism developed under Section 12 of the Carbon Credit Trading Scheme, 2023, as amended from time to time;"* (emphasis added)

The above clause seems to refer to extinguishment of the banked Carbon Credit Certificates (CCC) beyond an identified timeline. However, the draft regulation doesn't explicitly define the term "Extinguishment". Furthermore, the Detailed Procedure for Compliance Mechanism developed under Section – 12 of the Carbon Credit Trading Scheme, 2023, as mentioned in the draft clause, also does not refer or define extinguishment of CCCs'. The scope of banking and its extinguishment need to have a coherent definition across the Detailed Procedure for Compliance Mechanism document and in proposed regulations. Clarification with respect to the expiry of the CCC should also be defined clearly.

Clarification on the Term 'Banking': The Banking of CCC need to be explicitly defined in terms of any limit on the quantum and the tenure of such banked certificates. It is likely that an obligated entity possess banked certificate which it may not even able to utilize for the next compliance period as it would have achieved its obligated target. Would such 'banked' CCC be allowed to be further 'banked' for the subsequent compliance cycles (Figure 1).It needs to be clarified that banked certificate will be valid until redeemed (i.e. perpetual) or may have a limited validity for the subsequent compliance cycles.

Suggested Citation: Singh, A. (ed.). (2024), Opinion on CERC (Terms and Conditions for Purchase and Sale of Carbon Credit Certificates) Regulations, 2024 [Draft], In Power Chronicle (Vol. 07, Issue 03, pp. 10-13), Energy Analytics Lab (EAL), Indian Institute of Technology Kanpur. https://eal.iitk.ac.in/assets/docs/power_chronicle_vol_7_issue_3.pdf

In case an obligated entity has an inventory of banked CCC from an immediate preceding compliance cycle and prior compliance cycle, a vintage-based priority for trading of banked certificate on power exchanges should also be outlined. The First In, First Out (FIFO) approach may be adopted for the same.

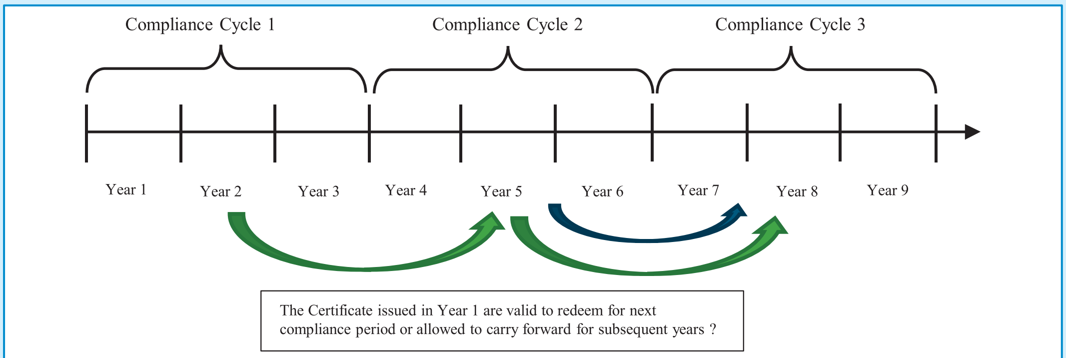


Figure 1: Life cycle of ESCerts

- **Scope of Forum:** Draft clause 2.1 (j) states that *'Market' means a **forum** or platform where buyers and sellers, buy or sell CCCs through a Power Exchange;"*(emphasis added)

  While a market platform refer to power exchanges, there is lack of clarity about the term **'forum'** referred in the draft document. The draft definition 2.1 (u) and (v) on maximum and minimum price for trade of carbon credit **only mentions power exchanges.** To ensure that there is sufficient liquidity and competitiveness in trading of carbon credits, CCC should be tradeable on a 'single' platform through coupling of power exchanges. Such coupling may be defined in the context of these regulations. The concept of 'forum' also needs clarification whether it means a platform other than power exchanges. Does it refer to such platforms it the international context?

- **Single or Multiple Trading of CCC:** The RECs are tradable only once on the power exchanges. Post settlement of a trade, the certificates cannot be traded subsequently through another session on the exchanges. The draft regulations should explicitly clarify that the CCCs are also tradable only once and cannot be re-traded.

- **COP29 - International Carbon Market:** Subsequent to the operationalisation of Article 6 of the Paris Agreement at COP29, the International Carbon Market may emerge soon. The draft regulations should also provide for international trading of CCC either directly or through other intermediaries. With the emergence of such an international market, validity of domestically credited certificate may need to be verified in-line with international benchmark, and traceability thereof.

- **Governance Framework for Registry:** Draft clause 5 states that *"Registry for the exchange of CCCs and shall establish the necessary framework for this purpose in accordance with Section 6 of CCTS 2023, as amended from time to time."*(emphasis added)

  The regulations should also specify the governance framework for the registry and its accountability thereof. Efficient benchmarks may be established for transparency and performance evaluation of the registry. The fees and charges leviable by the registry may also be defined.

- **Data Dissemination:** Draft clause 6.2 (c) states that *"disseminate relevant market information to all stakeholders"* as one of the function of the administrator. It is important to note that general public, civil society organizations and academic institutions play an important role in undertaking independent research. The scope and frequency of market information dissemination, and its archival should be clearly defined. An Application Programming Interface (API) based data dissemination may be mandated to disseminate market information.

- **Market Design Flaw vs Floor Price:** Price floors for Renewable Energy Certificates (RECs) were introduced to provide revenue assurance to the investors and, provide debt servicing assurance to the lenders. While the price floor itself is distortionary in nature as it vitiates economic signals and is often attempts attempts to address market design flaws, it may be introduced in the short-term to bring revenue assurance. Arguments against a REC floor price were enunciated by Singh (2010, 2009) [1][1]. It has often been noted, in case of REC as well as ESCerts, that these instruments are traded generally near or at the floor price due to significant oversupply of such instruments (Figure 2). **This points towards basic design flaw in such markets due to limited targets and weak compliance**

mechanism. The price discovery has been at the floor price most of the times over the last few years. This is a reflection of inherent value that the market of ESCerts has been placing on it due to significant oversupply. Artificial floor price would further enhance this supply. **The primary goal should be to address the reason for oversupply. This can be attributed to lenient targets as well as weaker compliance.**

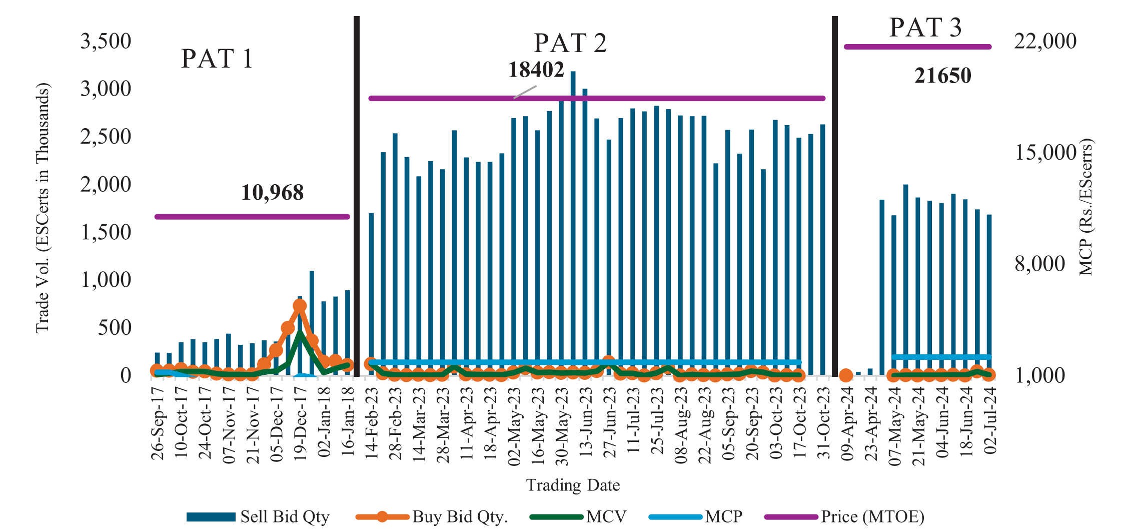


Figure 2: ESCert Trading PATs (IEX)

- **Floor Price vs Market Stability Mechanism for CCC:** In the presence of the properly designed CCC market framework, the need for setting floor & forbearance price would not ideally arise. Nevertheless, floor price may still be relevant as it provides certainty of economic signals for investment, in improvement of energy efficiency. **Defining a floor price is only the second best short-term solution, improvement in the target setting framework remains the primary solution.** Setting of floor price or forbearance price are short-term solutions for price fluctuation. As an alternate to setting a floor price, a CCC Market Stability Reserve may be set up in line with similar experience with the European Union Emission Trading Scheme (EU-ETS). Such stability reserve, can initially be funded by the government, and be made good with a small levy whenever prices are above a target level. The Carbon Credit Trading Scheme, 2023, notified on 28th June 2023, empowers the Bureau of Energy Efficiency (BEE) as the administrator of the scheme. **Its functions include development of a market stability mechanism for carbon credits. Given the provision for such a mechanism, the need for setting a separate floor price should not arise.** The objectives of such a mechanism would include the need to maintain a range of prices for the CCC and financing required thereof.

- **Bilateral Trade of CCC?:** Draft clause 4 states that *"These regulations shall be applicable to the CCCs offered for transactions on Power Exchange(s), including **contracts** in CCCs as approved by the Commission in accordance with the provisions of the Power Market Regulations."* (emphasis added)

  The above clause seem to suggest that CCC may be traded outside the PXs as well, perhaps in a bilateral manner. Clarification with respect to such contracts should be provided upfront.

- **Single Category of Certificates:** Draft clause 8.1 *"CCCs shall be categorized by the Bureau for the obligated and the non-obligated entities." Read along with proposed Clause 9.2 "There shall be **two separate market segments** in the Power Exchanges for dealing in CCCs, namely, Compliance Market for the obligated entities and Offset Market for the non-obligated entities."* (emphasis added)

  The Energy Conservation (Amendment) Act 2022, the Carbon Credit Trading Scheme, 2023 or its amendment issued in 2023 do not envisage multiple types of carbon credits for the types mentioned in the draft regulation. The draft regulation defines two categories of CCC for the obligation and for the non-obligated entities respectively. Such a categorization would be detrimental to the development of the CCC market in the country. Such differentiation not only would bifurcate and hence reduce liquidity across the two market segments but would leave no incentive for the non-obligated entities to make effort or invest for generating 'non-obligated' CCCs. ***Such artificial separation would essentially dry out the demand for the 'non-obligated' entities and would also raise***

cost of compliance for the obligated entities who would have limited supply of CCCs. Thus, a single type of CCCs should only be issued and tradable on the power exchanges. This segregation would also raise complexities for potential trading of such certificates in the international market, if enabled later.

- **'Dealing' in the Certification:** Draft clause 9.1 states that *"Unless otherwise specifically permitted by the Commission by order, the CCCs shall be* ***dealt*** *with only through the Power Exchange and not in any other manner."*(emphasis added)

  The term 'dealt with' lacks clarity of its scope. Does it mean more than trading? If not, it should be replaced with 'trading'. This would also avoid complexity introduced due to the term 'forum' included in clause 2.1 of the draft regulation.

- **Dispute Resolution - Role of CERC and the Appellate Tribunal:** It is suggested that an Appellant Tribunal must be identified to resolve any issue arising among stakeholders. For example disputes arising from credit seller cease to exist then the contract buyer will have to appeal the breach of contract. Which governing body does the buyer approach? Considering the above stated situation, Registry files a complaint alleging the buyer and seller are sister entities and are buying and selling within themselves. The Appellant tribunal must be set up to overlook upon concerned authority and dispute matters.

  The Energy Conservation Act 2001, the Energy Conservation (Amendment) Act 2022, the Carbon Credit Trading Scheme 2023 or its amendment issued in 2023 do not refer to a mechanism for dispute resolution in the context of the CCTS. Given the CERC's jurisdiction over the Carbon Trading Scheme, the Commission should also be empowered to adjudicate upon the disputes arising out of the scheme. Further legislative amendments may be required to ensure that a similar chain of the dispute resolution subsequently flows to the Appellate Tribunal.

- **Timeline for Report Submission by Power Exchanges:** Draft clause 9.10(Istates that *"The Power Exchanges, shall-*

  i. *send reports for the executed transactions, financial obligation, and all other relevant reports to the respective entities;*
  ii. report to the Registry, after every dealing session, details of the CCCs transacted by the eligible entities……"

  A timeline for reporting compliance should be included in the above clause. It is suggested that the Power Exchanges may/must submit the report to respective reporting offices within x hrs from the closing of the trading session.

- **Reporting to the Commission and Market Monitoring:** The data related to the CCCs offered for trade, cleared, and banked should be reported to the Commission within one week of the trading session. The scope of the monthly Market Monitoring Report issued by the CERC should also be expanded to include trading in CCCs.

- **Bidding Technique for Price Discovery:** Draft clause 11.2 *"The market price of CCC shall be as discovered through the process of bidding at the respective Power Exchange."*

  The above mentioned clause leaves the choice of bidding to the respective Power Exchange. For example, one of the exchange may adopt closed bid auction while the other may choose continuous bidding. To avoid potential for 'hand held' and non-competitive trades, closed bid auction should be specified by the Commission. It is noted that recently the Commission has proposed discontinuation of certain types of contracts. Adoption of continuous bidding is one of the reason for the same. The Commission may identify closed bid auction as the preferred approach for price discovery.

- **Typographical Correction:** Draft Clause 6.1 may be corrected for typographical error as *"For the purpose of dealing with CCCs issued under the EC Act, 2001, as amended from time to time, the Bureau shall act as the Administrator"*

Opinion on GRID-INDIA (Mechanism of Compensation for Degradation of Heat Rate, Auxiliary Consumption, and Secondary Fuel Oil Consumption Due to Part Load Operation and Multiple Start/Stop of Units) Regulations, 2024 [Draft]

Cite

The GRID-INDIA issued draft Regulation on, Mechanism of Compensation for Degradation of Heat Rate, Auxiliary Consumption, and Secondary Fuel Oil Consumption Due to Part Load Operation and Multiple Start/Stop of Units on 30th September, 2024.

Objective: The draft document addresses the mechanism for compensating for degradation in Station Heat Rate (SHR) and Auxiliary Energy Consumption (AEC), and the calculation of Secondary Fuel Consumption (SFC), along with the process for determining compensation. Generators are responsible for calculating the compensation and submitting the relevant data for verification and billing purposes to the Regional Power Committee (RPC). This ensures transparency, accountability, promotes efficiency and fairness in the compensation framework.

Key Highlights:

- **Fair Compensation:** Provide a mechamism for calculation of compensation of degradation in heat rate, auxiliary energy consumption, and secondary fuel oil usage.
- **Accountability:** The compensation amongst other beneficiaries shall be shared in the ratio of unrequisitioned energy below 85% of their entitlement for the calculation period.
- **Data-Driven Decision:** A mandate for accurate data submission by generators to RPCs for validation and periodic review.

EAL Opinion

The Role of Mechanism of Compensation in Power Generation Operation: The mechanism of compensation for degradation in power generation is essential for enhancing efficiency and reliability. It involves continuous performance monitoring to assess the impact of part load operation and frequent cycling on key metrics like heat rate and fuel consumption. Additionally, this mechanism promotes operational optimization and stakeholder transparency, fostering a culture of continuous improvement. Ultimately, it supports the economic viability and sustainability of power generation, contribution to a more efficient energy landscape.

As highlighted in CER opinion on draft CERC (Terms and Conditions of Tariff) (First Amendment) Regulations, 2024-Part Load Compensation for Auxiliary Energy Consumption and Station Heat. Design of part load compensation mechanism largely on the basis of data submitted by the regulated entities and it suffers from information asymmetry as well as sample selection bias. The regulatory principles, in contrast, should utilise efficient operating benchmarks with appropriate adjustment for the local conditions. The amendment's proposal should thus be examined in light of wider operational data leading to recalibration of the compensation. Grid India should mandate submission of operational data by the regulated entities so that an in depth analysis can be conducted under a research study, thus assisting CERC to set efficient norms.

Draft clause 1(vii) states that *"Effective Capacity in MWhr means the maximum possible generation from a station during the calculation period.*

Total Installed Capacity of the designated generating station (in MWhr) is ***minus*** *Installed Capacity (MW) of the Unit(s) of the said station under outage (planned or forced outage) and under reserve shut down during the calculation period X outage time…."* (emphasis added)

The above clause may be modified, for clarity, as *"Total Installed Capacity of the designated generating station (in MWhr)* ***excludes*** *Installed Capacity (MW) of the Unit(s) of the said station under outage (planned or forced outage) and under reserve shut down during the calculation period X outage time…."*

Suggested Citation: Singh, A. (ed.). (2024), Opinion on GRID-INDIA (Mechanism of Compensation for Degradation of Heat Rate, Auxiliary Consumption, and Secondary Fuel Oil Consumption Due to Part Load Operation and Multiple Start/Stop of Units) Regulations, 2024 [Draft], In Power Chronicle (Vol. 07, Issue 03, pp. 14-16), Energy Analytics Lab (EAL), Indian Institute of Technology Kanpur. https://eal.iitk.ac.in/assets/docs/power_chronicle_vol_7_issue_3.pdf

[1] Singh, A. (ed.). (2024), Opinion on CERC (Terms and Conditions of Tariff) Regulations [Draft], In Regulatory Insights (Vol. 6, Issue 04), Centre for Energy Regulation (CER), Indian Institute of Technology Kanpur. (cer.iitk.ac.in/regulatory_insights)

Draft clause 1(viii) states that *"For ECR (Comp)" means an increase in the normative Energy Charge Rate in Rs/kWh for the calculation period considering degraded SHR and AEC based on average unit loading..."* (emphasis added)

ECR (Comp) is incremental charge, and thus may be suffixed with roman delta for clarity.

- **No Compensation Based on 85% of Declared Capacity (DC):** Draft clause 2.1(ix) states that *"No compensation shall be payable by beneficiaries if it has requisitioned at least **85% of its entitlement** during the calculation period."* (emphasis added)

  This may be modified, for clarify, as *"No compensation shall be payable by **a beneficiary** if it has requisitioned at least 85% of its entitlement during the calculation period."* (emphasis added)

- **Data Transparency:** Draft clause 2(v) states that *"The compensation to be paid to designated stations for the calculation period ending the nth month shall be the difference in the **ECR (SE) and ECR (DC) for that period ECR (Comp)** for the calculation period ending nth month shall be calculated."* (emphasis added)

  Data related to all calculations including ECR (SE) and ECR (DC) should be reported in detail and be archived on the respective RLDC website. Uniform format for reporting detailed and disaggregated data with block wise schedule, and uniform reporting protocol should be adopted across all RLDCs. Apart from pdf reports, data including calculations should be available in Excel format on the respective website.

- **Significant Impact of Secondary Fuel Oil Consumption:** Draft clause 2.1(vi) states that *"The summation of energy forecast (MWh) for various consumer categories upon adjusting for the compensation Compn (P) payable to CGS/ISGS for the calculation period ending nth month calculated Compn (P) = (Total Generation Schedule (Energy) to its original beneficiaries excluding schedule under TRAS, SRAS & bilateral sale/ collective sale under open access) * ECRn (Comp)*

  *ECRn (A) for the calculation period shall be calculated using actual values of SHR and Aux Consumption furnished by CGS/ISGS at the end of the calculation period and **normative secondary fuel oil consumption** as per CERC Tariff Regulation for."* (emphasis added.)

  The calculation of ECR (A) should use actual rather than normative secondary fuel oil consumption otherwise it would be a misnomer to its very spirit.

- **Compensation only for Cost Incidence Effective Generation Must Include Bilateral And Collective Sales:** Draft clause 1(xi) that *"Effective Generation in MWhr means the actual generation ex- bus of the designated station or the Schedule generation excluding the schedule under TRAS, SRAS and bilateral sale/ collective sale under open access during the calculation period..."*

  The spirit of the CERC regulation is to provide compensation for the cost incurred in due to part load operation (before 85% of DC). Apart from utilisation of the URS, untilised DC of a generating unit can be scheduled for TRAS, SRAS as well as under bilateral/collective transaction. This would enhance the overall schedule for the available DC, and **would thus avoid any additional cost due to part-load operation. <u>Compensation for a cost not incurred should not be burdened on the beneficiaries</u> and hence the final consumers. Any part load compensation on account of TRAS/SRAS down should be recoverable from the Deviation and Ancillary Service Pool Account.**

  Figure 3 shows TRAS Up/Down (MU) from June, 2023 to October, 2024. It is analysed that TRAS Up/Down increases, with frequent dispatch adjustment that results in +84 MU in case of TRAS Up and -124 MU for TRAS Down to meet fluctuating demand. EAL observed that significant increases in quantum/instruction for TRAS Up/Down during peak demand month from April to June 2024 when energy met reaches around 5466 MU. During non-peak months, average of TRAS Down is higher as compared to average TRAS Up.

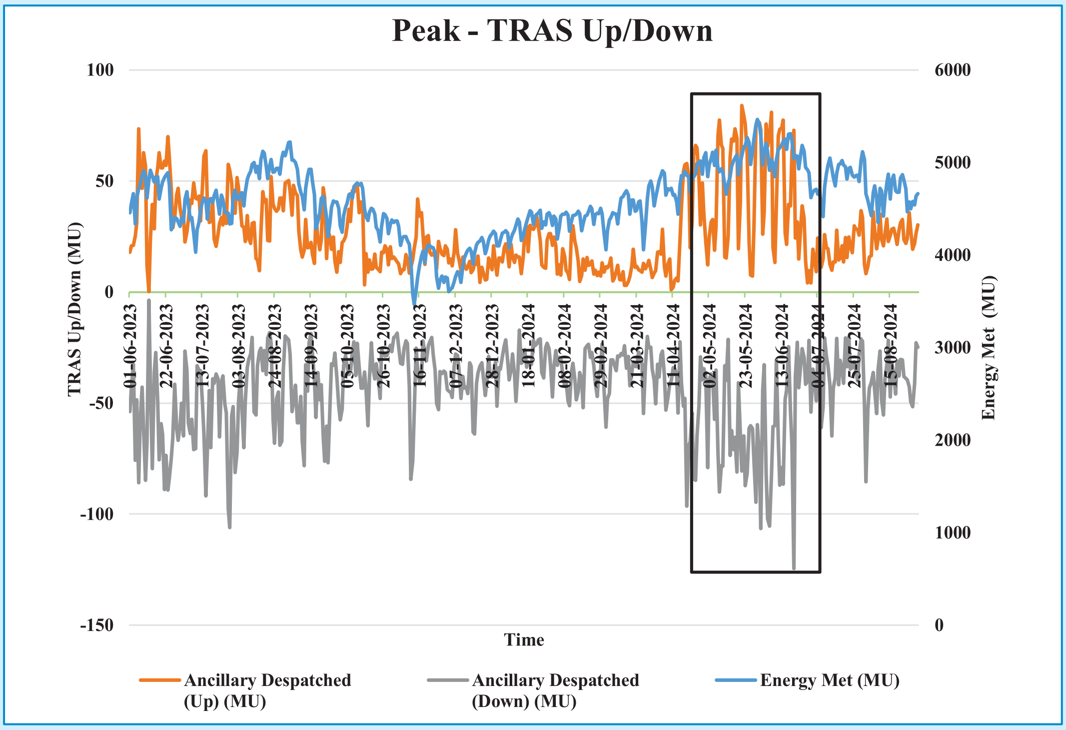


Figure 3: TRAS Up and Down in MU

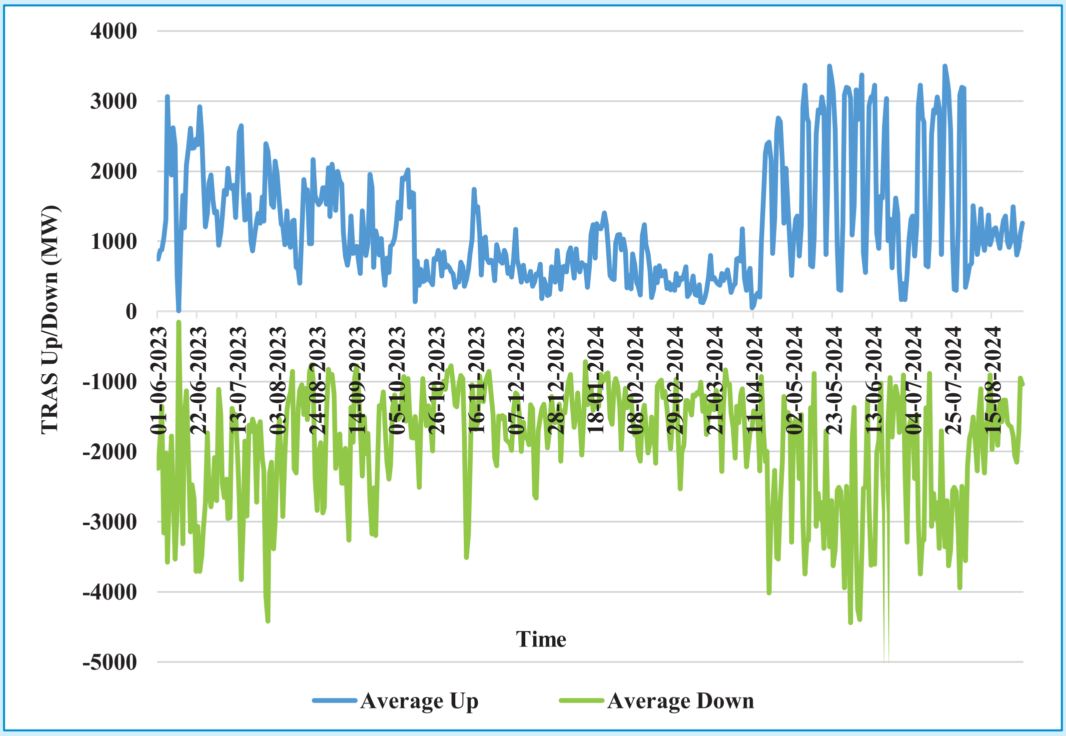


Figure 4: Average TRAS Up and Down in MW

Figure 4 shows that the average TRAS Up and Down (MW) from June 2023 to October 2024. It is observed that the average TRAS (Up) vary between 0 to 3.5 GW and TRAS (Down) vary between 0 to -5.1 GW with notable peak during April to July 2024. During non-peak months the average TRAS (Down) value variation between -1 to -3.5 GW. Whereas average TRAS (Up) is 0.5 to 1.5 GW during non-peak months. **Given the significant impact TRAS/SRAS up schedule can have on the DC utilisation, its role in 'avoidance' of part load operation of thermal generating units should not be undermined.**

Opinion on CEA Discussion paper on (Methodology for Capacity Credit of Generation Resources & Coincident Peak Requirement of Utilities under Resource Adequacy Framework), 2024 [Draft]

Cite

The Central Electricity Authority issued discussion paper on, Methodology for Capacity Credit of Generation Resources & Coincident Peak Requirement of Utilities under Resource Adequacy Framework on 06th December 2024.

Objective: The Central Electricity Authority has issued a discussion paper exploring various methodologies for evaluating the capacity credit of solar, wind, and other renewable energy sources, these methodologies include the top 10% demand hours, solar vs. non-solar, and critical day methods. Accurate capacity credit estimation is essential for state and distribution utilities to determine the capacity required from various resources to meet their coincident peak demand obligations, particularly during the 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.

EAL Opinion

Methods for Coincidental Peak Calculation: This discussion papers illustrates *(Refer section 3.0 "Coincident Peak")* alternate methods to calculate the coincidental peaks. Average of top 5% peak demand presents a risk of under estimation of the expected peak. We can note from the load duration curve of all India electricity demand that top 5% of the time blocks. Represent peak demand that has a significant range (Figure 5).

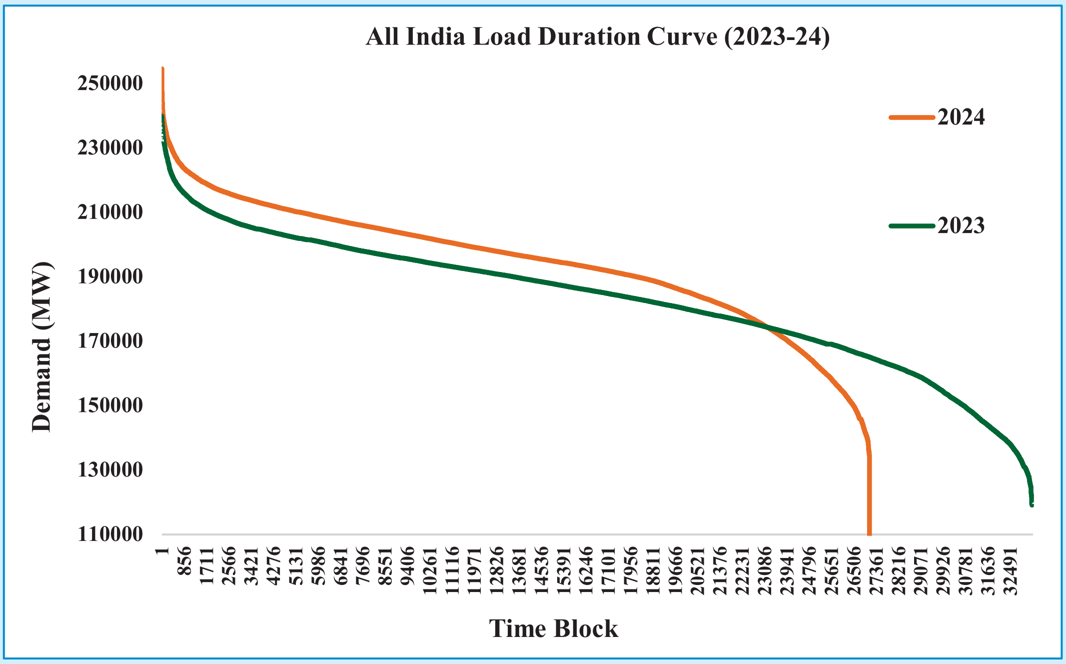


Figure 5: All India Load Duration Curve (2023 and 2024)
Note: Data up to 18th Dec 2024

For example, for part of the 2024 data, this ranges from 219 to 254 GW Power demand with an average of 236.5 GW. Use of the average of top 5% of the demand leaves with an underestimation of about 17.5 GW (14.4 GW in 2023) to the highest peak demand observed. Similar difference across the top 2% hours comes to 14.5 GW (11 GW in 2023). Similar differences are observed across the maximum and the median demand as well. Thus, average as well as median of top 5% or even 2% of the peak demand hours would not adequately represent the peak demand faced in a year.

Suggested Citation: Singh, A. (ed.). (2024), Opinion on CEA Discussion paper on (Methodology for Capacity Credit of Generation Resources & Coincident Peak Requirement of Utilities under Resource Adequacy Framework), 2024 [Draft], In Power Chronicle (Vol. 07, Issue 03, pp. 17-25), Energy Analytics Lab (EAL), Indian Institute of Technology Kanpur. https://eal.iitk.ac.in/assets/docs/power_chronicle_vol_7_issue_3.pdf

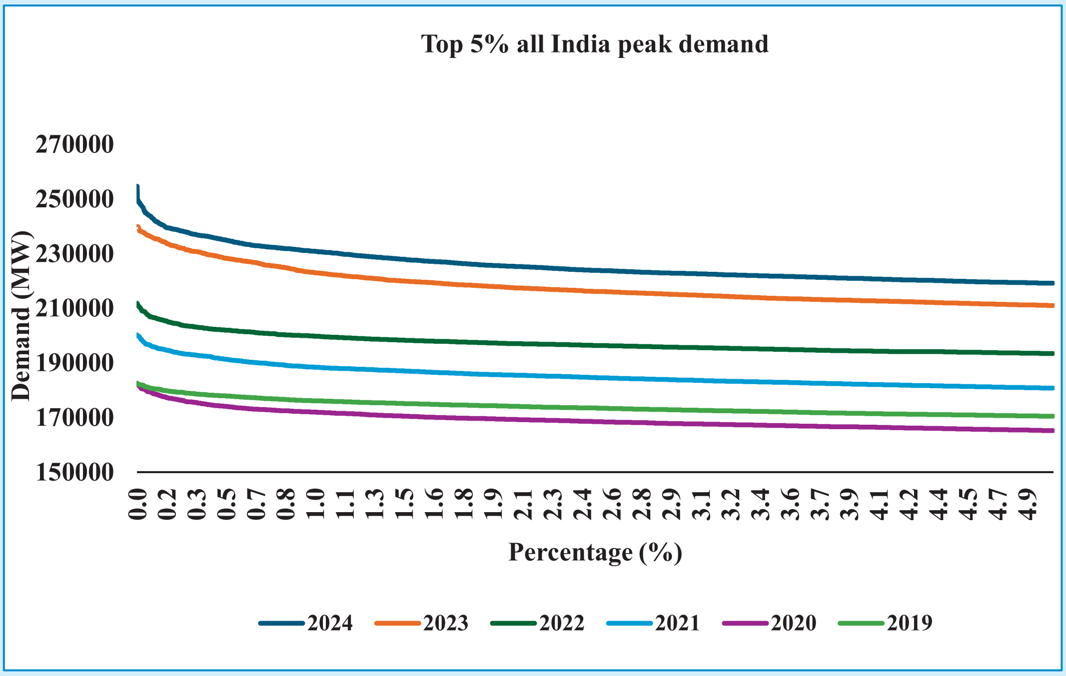


Figure 6: Top 5% all India demand data

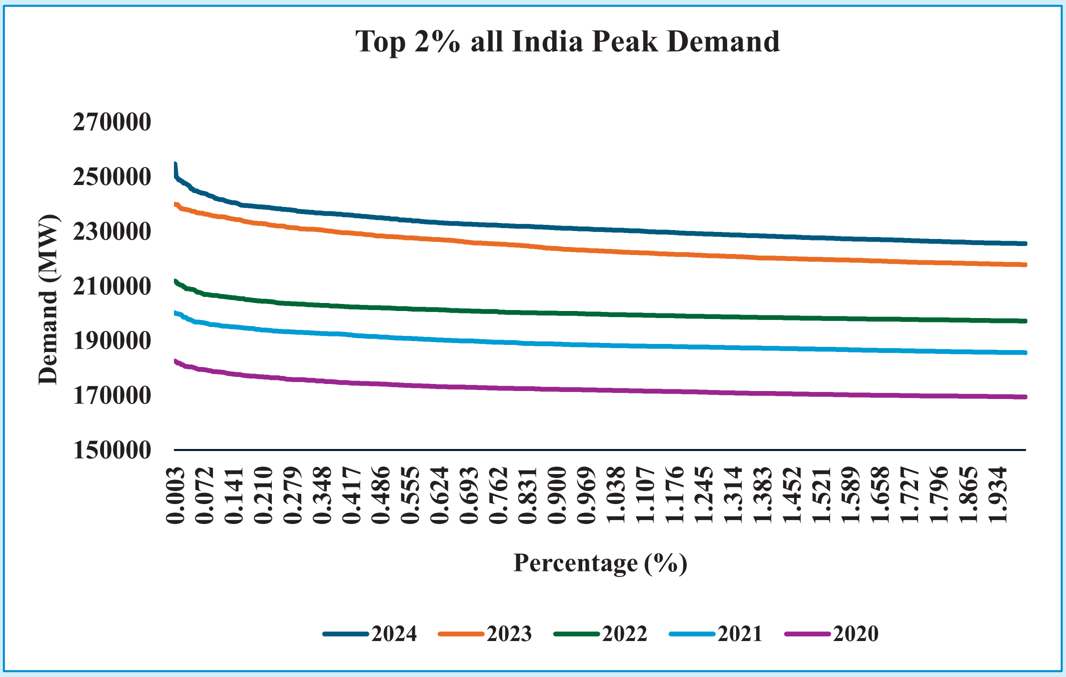


Figure 7: Top 2% all India demand data

- **Choice of Percentiles for Peak Demand Hours:** Planning for the peak national demand with Planning Reserve Margin (PRM) required identification of high demand hours wherein various states are contributing in different proportions. In Table 2 below, we present analysis of different percentile values of demand and their difference from the observed peak demand across years. It can be observed that selection of 95th percentile of the top 5% of demand hours also does not reflect the actual peak demand observed in the respective years. In fact, the difference has been rising over the years, in general. This highlights the growing peakiness of demand over the years. For the year 2024, the difference between the 110th and the 95th percentile is estimated to be 16.27 GW. The observed peak demand was about 6.8% higher than the 95th percentile rising from 3.36% during the previous year.

Table 2: Percentile (P) Calculation for top 5% Demand (2019-2024)[1]

Top 5% Demand (MW)	2024	2023	2022	2021	2020	2019
80th Percentile (P)	234497	223937.8	200110	188346	172321.3	176125.8
90th Percentile (P)	236829.5	229077.1	202439.6	191296.5	174517.8	177885.6
95th Percentile (P)	238473.5	232029.8	204445.7	193428.7	176422.9	179238.4
100th Percentile (P)	254746	239826	211229	200264.4	178505.9	182640.3
100th (P) – 95th (P)	16272.5	7796.2	6783.3	6835.7	2083	3401.9
100th (P) – 90th (P)	17916.5	10748.9	8789.4	8967.9	3988.1	4754.7
100th (P) – 80th (P)	20249	15888.2	11119	11918.4	6184.6	6514.5

Solar Rooftop Installations, and Demand across Solar and Non Solar Hours: As per the defined solar and non-solar hours, load duration curve across the two are significantly differentiated (Figure 8 & 9). Such demand profile may have significant impact on peak demand assessment for few of the states. Uncertainty associated with peak demand during solar hours is expected to grow with increasing penetration of behind the meter solar PV installations, especially post implementation of the PM Surya Ghar Yojna. We suggest two ways to address this – (i) identify solar generation profile from solar rooftop installations or (ii) incorporate uncertainty in demand profile during solar hours.

This also highlights the need for greater visibility of generation from solar rooftop installations, data archival and analytics thereof[2]. Smaller installations may be covered on a sampling basis with increasing sampling proportion for larger installations.

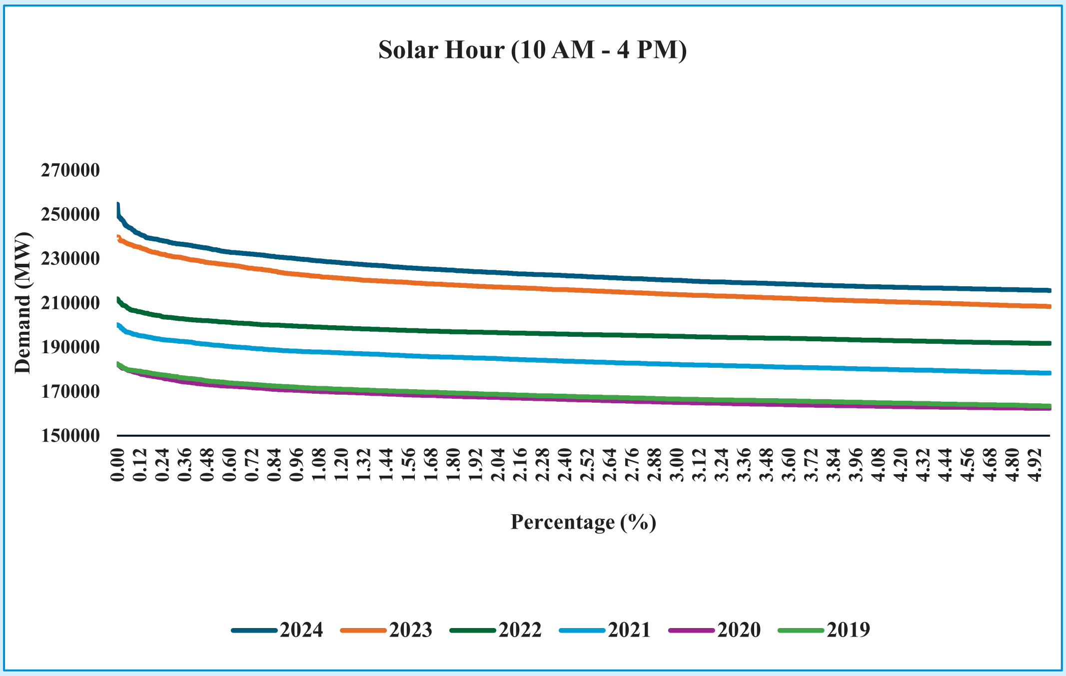


Figure 8: Load Duration Curve (Top 5% of Solar Hours)

[1] The data presented here may not match exactly with that presented in the CEA's discussion paper.
[2] Singh, Anoop (2024), "MNRE (Guidelines for Implementation of PM-Surya Ghar: Muft Bijli Yojana for Component to "CFA to Residential Sector"), 2024 [Draft]", Regulatory Insights, Centre for Energy Regulation (CER), Indian Institute of Technology Kanpur, Volume 7, Issue 1, ISSN: 2583-2182 (O). https://cer.iitk.ac.in/periodicals/regulatory_insights/Volume07_Issue01.pdf

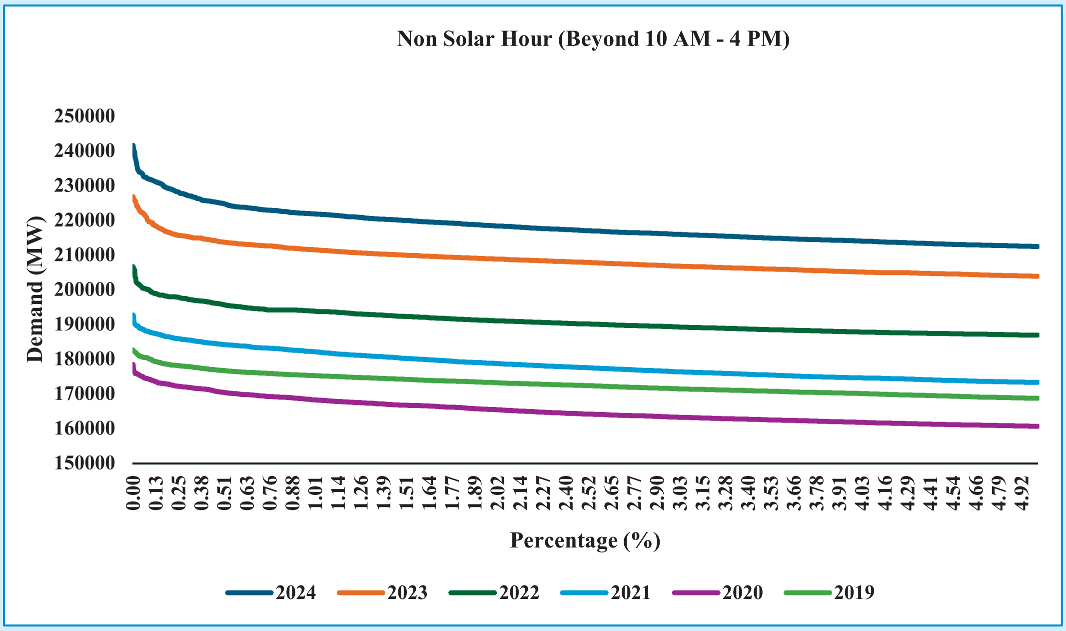


Figure 9: Load Duration Curve (Top 5% of Non-solar Hours)

- **Demand Vs Energy Uncertainty:** The guidelines for RA mandate its planning on hourly basis. Hourly demand can be arrived at either by averaging 15-minute demand data or by using maximum demand observed across the four blocks of an hour. The later method is used by CEA in its methodological approach. Either of the approach leads to uncertainty in undertaking a resource adequacy study. Averaging of demand does not reflect the actual demand observed during the hour.

  Use of highest of demand across four blocks of the day would lead to overestimation of demand in energy terms. An attempt to adjust the demand profile to match with the forecasted energy forecast would need downward adjustment of the peak demand. **This dichotomy of uncertainty can be addressed by use of 15-minute block data. In our earlier opinion3, 15-minute block basis was suggested for undertaking a resource adequacy study.**

- **Regulatory Framework for Power Procurement and Provision under RA Framework:** The methodological approach to RA outlines that the discoms should ensure adequacy of resources to meet its contribution to the national peak, during solar as well as non-solar hours. As per RA framework, a discom with a forecasted peak demand during solar hours would also be required to ensure resource adequacy (including PRM) for the coincidental contribution of a discom's demand to the national peak, which may be forecasted to be observed during off-peak hours. This would entail additional cost for the discom. The regulatory framework for power procurement provides for procurement of power to meet discom's requirement. **Would such additional cost be burdened to consumers of such a discoms, and would it be approved by the respective SERC?**

  At the same time, the other discoms, whose peak demand coincides with the national peak would also be required to ensure adequacy of resources to meet their own peak demand, and thus would procure power for the same. This will have approval of the respective SERCs. **The overall cost of ensuring resource adequacy may be higher.**

- **National Vs Discom level Planning Reserve Margin (PRM):** The approach to estimate national PRM, as per proposed methodologies in the RA Guidelines, needs to ensure that the uncertainties associated with both demand as well as supply side are taken into account. A separate discussion paper may be floated for wider consultation.Post calculation of PRM at the National level, state level PRM should be estimated considering the non-coincidental nature of the peak demand across discoms (Figure 10). **A uniform PRM of 5% across discoms, in this example, could result in higher PRM at the national level. Aiming to achieve the same would thus result in high cost incidence for the discoms and, hence, the end consumers.**

  The non-coincidental nature of peak demand across discoms highlights that to achieve a targeted national PRM, say 5%, the PRM over the forecasted peak demand for the respective discoms need not be as high as 5%.With growing procurement of (cheaper) solar power, a number of discoms consider active demand management whereby supply to agricultural consumers is restricted to solar hours, thus lowering its impact on the demand profile. Impact of such active demand management should be built into the future RA requirement. Similarly, impact of lower tariff during solar hours would also shift some of the household demand to these hours.

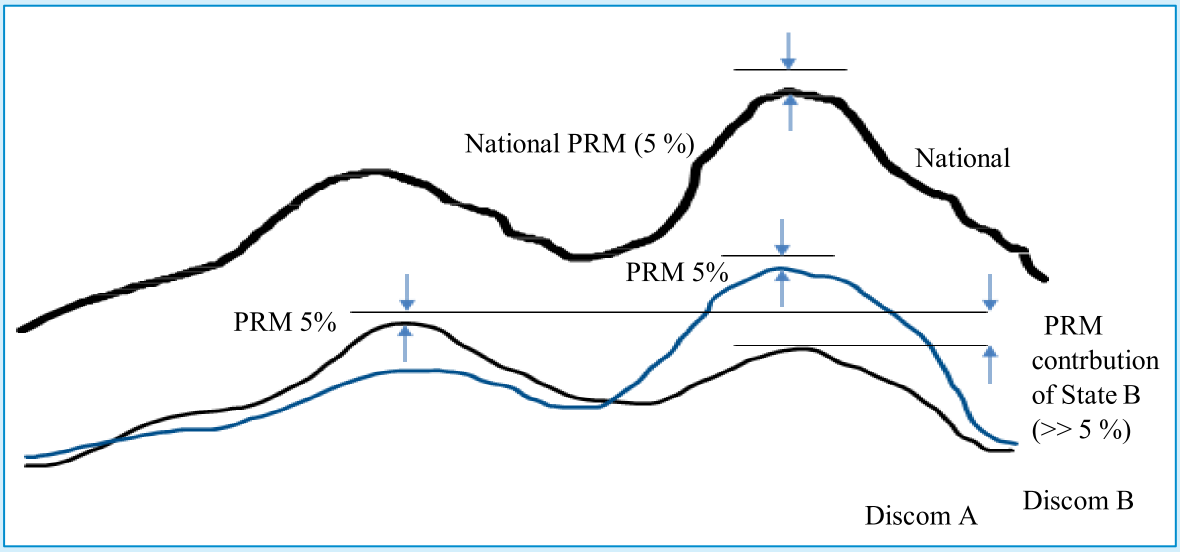


Figure 10: National Vs discom level PRM

Nevertheless, differentiation across solar and non-solar hours should be taken into account while ensuring RA. For example, a PRM of 5% tied up by State A through solar based resources would not contribute to the PRM during national peak. However, baseload resources during the non-solar hours may be sufficient to ensure 5% PRM contribution to national peak. Further analysis should be undertaken to understand the impact of such an approach.

With growing procurement of (cheaper) solar power, a number of discoms consider active demand management whereby supply to agricultural consumers is restricted to solar hours, thus lowering its impact on the demand profile. Impact of such active demand management should be built into the future resource adequacy requirement. Similarly, impact of lower tariff during solar hours would also shift some of the household demand to these hours.

Nevertheless, differentiation across solar and non-solar hours should be taken into account while ensuring resource adequacy. For example, a PRM of 5% tied up by State A through solar based resources would not contribute to the PRM during national peak. However, baseload resources during the non-solar hours may be sufficient to ensure 5% PRM contribution to national peak. Further analysis should be undertaken to understand the impact of such an approach

- **Coincidental Peak of the State or Discom:** The methodology to determine the coincident peak demand with top 5% Demand Hour Methodology includes the following steps. *(Refer clause 3.0)*

  i. Collect the demand profile of each state for the last 2-3 years.
  ii. 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.
  iii. Prepare load duration curve (LDC) for the above demand profile.
  iv. Filter the top 5% of National Peak demand hours.
  v. 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. (emphasis added)

  The proposed methodology refers to demand of the 'State', which may include multiple discoms including those from public as well as private sector. The requirement for RA lies with respective discoms and hence that should be the unit of analysis and calculations thereof. 'State' may thus be replaced with 'discom'.

- **Coincidental Peak Demand During Solar and Non-solar hours:** The methodology followed for the calculation of Coincident Peak Demand during Solar and Non- Solar hours, outlines the last step as "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." (emphasis added)

The approach thus suggests to identify 'coincidental' peak of a state (discom) based on the choice amongst the alternate measures i.e. maximum, 90 percentiles or average of the observed demand, amongst the top 5% of the all India peak demand hours, which gives a 'coincidental' demand that sums up closest to the observed national peak in the historical data. This approach artificially picks up 'non- coincidental' demand across the states (within, say, 90 percentiles of top 5% demand hours) so that this adds up to the observed national peak. This approach thus, in fact, uses a sum of such 'non- coincidental' peaks. This sum may even sometimes be higher than the national coincidental peak. An error thus gets introduced due to 'non-coincidental' nature of demand across states. Each state would thus have to use 'non-coincidental' peak demand across solar and non-solar hours to work on its resource adequacy plan. This is not in line with the basic philosophy outlining 'coincidental' natural of demand.The state (discom)-specific peak demand that would be closest (in fact exactly equal) to the observed coincidental national peak would be the actual coincidental peak observed across states/discoms as per the original data itself. Thus, an alternate approach would be to use top 0.2-0.5% of the top demand hours. This would preserve 'coincidental' nature of state/discom-wise contribution to the national peak demand. A high percentile of data would be chosen in such a manner that the any residual gap, due to departure of the sum of coincidental peak across states from that observed for the national peak, is within the planning reserve margin (PRM)[4]

- **Planning for Optimal Power Procurement Vs Planning for RAR:** Resource Adequacy framework emphasizes on power procurement tie-ups for meeting state/discoms contribution to the national peak. It does not prescribe optimality of such decision. Discoms should plan for optimal power procurement taking into account techno-economic characteristics as well as availability of various capacities across time-blocks of the day to meet the RAR. The capacity factor and the LCOE of a technology may not be monotonically related. An optimisation model can examine this in a broader context while still adhering to RAR mandate.

- **Capacity Credit for Demand Response:** Calculation of Resource Adequacy Requirement (RAR) should explicitly provide for expected contribution of the Demand Response (DR) measures (Figure 11). **Such contribution of DR should be demonstrated through presence of appropriate quantum of capacity signed up with estimation of actual feasible deployment of DR. The SERCs/JERCs should issue regulations guiding design of appropriate DR program by the distribution licensees/aggregators.** Depending on economic signals, the projected DR would still have some uncertainty associated, and should be accounted for.Given the associated uncertainty, capacity credit for DR may be prescribe in the range of 0.6-0.7.

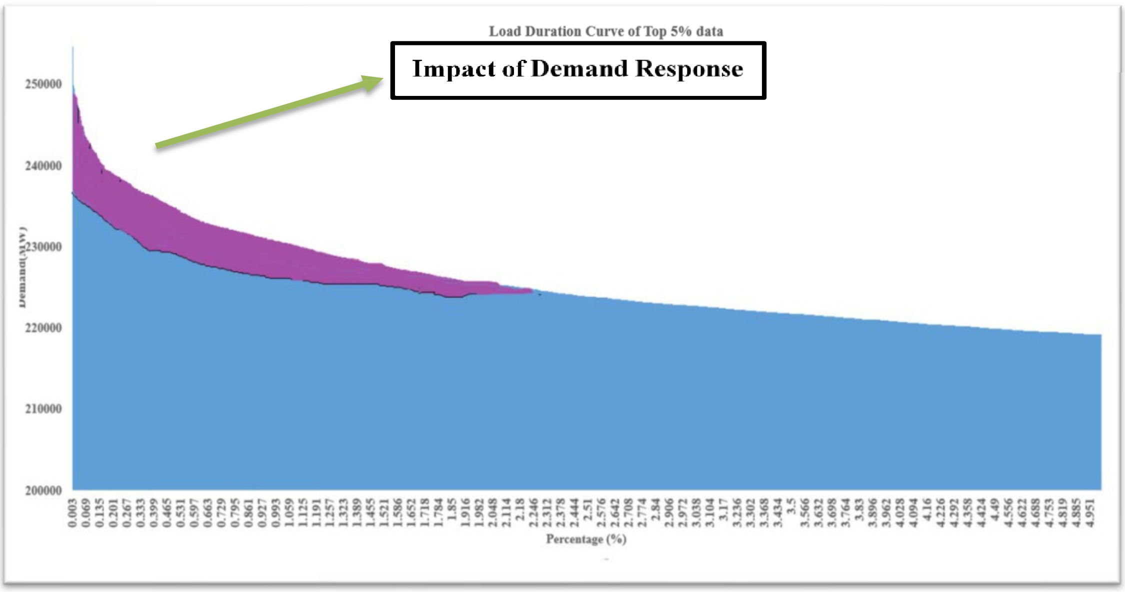


Figure 11: Impact of Demand Response - Load Duration Curve (LDC) of Top 5% Demand Hours

[4] (Sum of coincidental peak across states/discoms – Coincidental national peak) *100 / Coincidental national peak <= PRM

Role of Banking and Its Capacity Credit: Distribution licensees, with complimentary of demand profile, resort to banking of power across seasons (Figure 12) as well as hours of the day. **Demonstrated enforceable banking agreements, aimed at meeting the state/discom level peak, for the upcoming year may be considered as a resource available for meeting the RAR.** The philosophy of 'sharing' such capacity is underlined in the non-coincidental nature of the national and the state/discom level peak. A capacity credit of 0.6-0.7 may be considered for such banking arrangements if injection of such power does not coincide with the peak demand hours (solar/non-solar) of the injecting discom, and drawal of power coinciding with the peak demand hours (solar/non- solar) of the drawee discom.

To ensure that the banking arrangements are dependable and enforceable, **model banking guidelines for banking** across discoms may be introduced though consultations at the Forum of Regulators (FoR). These guidelines should ensure minimum 50% of the banked energy deliverable during identified hours across the shared seasons, with incentives (in kind, in energy terms) for delivering more than 50% benchmark during the period identified by the drawee entity. **Based on certainty associated with the banking arrangements to meet the RAR of a discom, adequate capacity credit 0.7-0.8 may be proposed for the same.** Another innovation would be to introduce **market-based banking arrangements,** which may be cleared through the power exchanges. This would not only ensure enforceability but also bring greater efficiency and competitiveness in banking transactions.

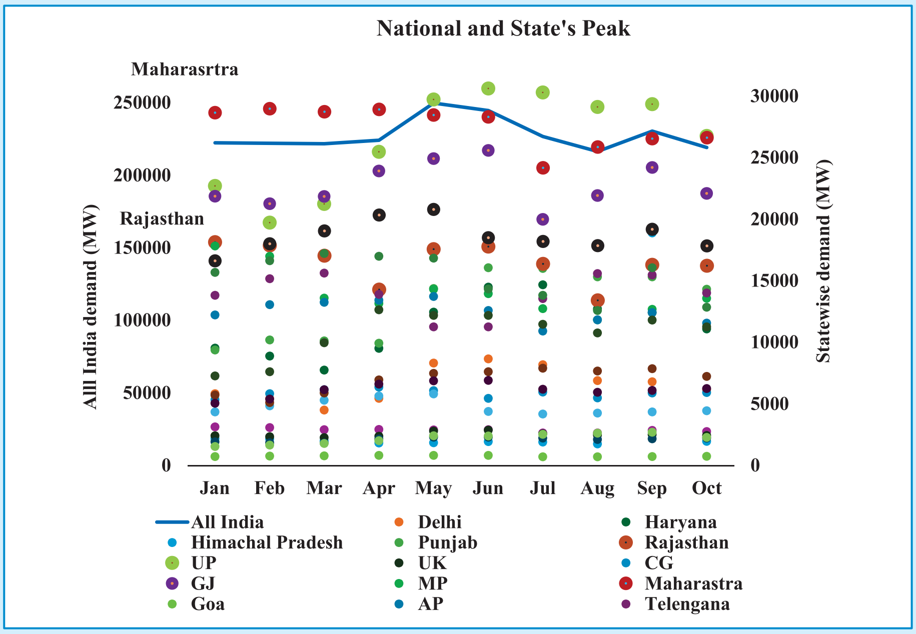


Figure 12: State-wise and All India Peak Source: Energy Analytics Lab (EAL), IIT Kanpur

Capacity Credit (CC) Calculation for the Thermal and Hydro Generators: *"The capacity credit for conventional sources based on the historical generation figures has been estimated in Table 1.*

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*

Coal-based thermal power plants continue to provide baseload resources contributing significantly to baseload requirement. Availability of such generating capacity, once adjusted for auxiliary consumption is expected to be available fully during high demand season. Any planned maintenance is, therefore, scheduled during low demand season. Under strained supply conditions, such planned maintenance sometime leading to higher probability of forced outages. **With better maintenance scheduling, capacity credit for coal-based generating plant merits to be set at a higher value. CEA may propose a framework for harmonized and optimal maintenance scheduling for generating assets across the country.**

Furthermore, regulated tariff framework for the inter-state as well as intra-state generating plants provides for full recovery of capacity charges only if such plants achieve a minimum availability of 85%. Except old plants, where some exceptions are also granted, most of the plants tend to ensure 85% availability on an average across the year. Therefore, **a minimum capacity credit of 0.8-0.85 be considered for coal-based generation plants/contracts.** Further analysis of availability across thermal power plants may be undertaken by the respective discoms/states to set appropriate value of capacity credit for the same.

Capacity credit for gas-based generating plants has significant economic connotations. Based on availability of gas/liquid fuel, this capacity is deployable and may merits higher capacity credit than suggested in the discussion paper. In the case of hydro power, there is significant variation across the years. **For states with peak season coinciding with monsoon season, availability of both RoR as well as those with storage capacity may be set dynamically based on historical performance.** Nevertheless, uncertainty with hydro resources would remain.

- **Variable Capacity Credit across Seasons and across Discoms/States:** The vintage of the tied-up generating assets, maintenance schedule and fuel tie-up would influence the capacity credit for the respective capacity. **Thus capacity credits, especially for coal-based capacity, should be differentiated across the plants, and updated from time to time. The CEA may bring forward a framework for assigning such capacity credit for the ensuing planning year.** This would not only ensure that discoms/states have flexibility in approach to set capacity credit based on **Variable capacity credits may be adopted across the seasons, especially those in the context of hydro generation capacity.** Similar approach should be adopted to account for seasonality associated with solar as well as wind resources. A study may be undertaken to develop such a framework with objective criteria for the each of the key factors influencing availability of the capacity.
- **Capacity Credit for Solar and Non-solar hours:** Differentiated capacity credit needs to be defined for few of the technologies across the solar and the non-solar hours. Storage based hydro resources are particularly deployed during the non-solar peak hours and thus should be earmarked higher capacity credit for such hours. This can be derived on the basis of historical despatch experience across the respective discoms.
- **Capacity Credit for Biomass Based Generation:** Biomass availability is seasonal in nature. However, regulated tariff framework across the country provides for up to 4 months of fuel inventory across the year. This should provide for greater availability for such capacity. Based on historical experience, capacity credit may be revised and differentiated across seasons
- **Poor Data Visibility:** Subsequent to the issue of latest IEGC 2023, the sector is witnessing a drought for data availability in public domain. For example, scheduling and despatch related data available through WBES is no longer accessible in the public domain. Such data has been and would support numerous independent studies and would further develop research ecosystem. **Urgent steps are required to ensure that such data is made accessible, with some latency, if required.**
- **Capacity Credit for ESS:** Energy Storage Systems (ESS) may have capability to supply stored energy during morning/evening peak (or any other time required) based on its capacity to undertake a 1 or 2 cycle operation in a day. Discoms should adopt appropriate Capacity Credit based on the contractual arrangement for such ESS.
- **Capacity Credit of Firm Despatchable RE (FDRE):** A number of discoms have entered into long-term contract for FDRE resources. The Capacity Credit for such a hybrid technology basket with storage is higher and be considered as it is. Since RA is with respect to the contracts, rather than the underlying capacity, firm despatchable capacity from FDRE resources may be assigned a capacity credit of 0.6-0.7. Further analysis, based on the respective contract, may be undertaken to ascertain this across discoms.
- **Economic Viability and Cost Optimisation:** *Refer Section 2.1 Mathematical Modelling for Resource Adequacy: "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."*

The EAL has engaged in long-term demand forecasting and power procurement planning based on long-term optimisation model for the states of Uttar Pradesh and Chhattisgarh. Such analysis minimises the cost of procurement across the planning horizon, generally 10 years. The **LCOE based approach assesses the respective technology on a stand-alone basis and is not the appropriate methodology for identifying cost effective generation mix. In contrast, the methodological approach for power procurement planning is based on a systems approach considering techno-economic parameters and system constraints thereof.**

- **Role of Captive Generating Sources in the RA:** The RAR approach considers only resources tied up by the discoms. The nation has about 128 GW of captive generation capacity (excluding solar and wind) that partly or fully serves the need of captive consumers as a source of continuous supply or as emergency backup. Based on their economics, some part of this capacity is available through the power market, including the power exchanges.The Electricity Act, 2003 has adequate provisions to ensure availability of such resources, especially under contingencies leading to shortage of generating resources. Furthermore, such sources can also be requisitioned and deployed by the system operator through ancillary services. A part of such capacity is thus 'available' and should be considered towards RAR or PRM.

  It is suggested that CEA, in consultation with the RLDCs/SLDCs, should capture load profile/grid interaction of such consumers as to improve visibility of such captive capacity. Further analysis may reveal potential for 'availability' of such capacity towards RA across the nation.

- **Capacity Based 'SCED' or Capacity Market for Resource Adequacy Planning:** Long-term power procurement planning should provide an economic roadmap for a Discom to meet its RAR. The intermittent phases (months to years) of excess or shortage of capacity is nevertheless going to be witnessed across discoms. Capacity markets can help address this gap in an incremental manner i.e. for add-on capacity requirement or the need to off-load excess capacity. Such marginal optmisation of short-term capacity is akin to optimisation on the margin undertaken in the Security Constrained Economic Despatch (SCED).

- **RAR for Distribution Licensees:** Draft clause 4.1, *"Capacity Credit in Resource Adequacy Framework "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 LNRAP 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)"

  As mentioned above the RAR for the distribution licensee places precedence on the discoms contribution to the national peak, whereas its own peak demand may warrant different strategy for the RAR for the specific distribution licensee. Furthermore, as also highlighted above, due to non- coincidental nature of peak demand across discoms, discom-wise differentiated PRM (which may be lower than national PRM) would still be able to assure the targeted national level PRM.The regulatory framework for power procurement across states, thus far, provides for approval of power purchase by a distribution licensee to meet its own (peak) requirement. Tariff policy 2016, should be amended to provide a framework wherein each discom 'contributes' to meet the national peak demand, which may be higher the power procurement, to meet its own peak demand. The issue of additional cost burden, and a mechanism to share the same, would also need to be addressed. In contrast, a discom level power procurement plan. Development of capacity market for 'add on' capacity procurement can help address these issues including 'socialisation' of cost towards procurement of 'incremental' resources to meet the national peak plus the targeted PRM.

Opinion on AERC (Demand Response) Regulations, 2024 [Draft]

Cite

Assam Electricity Regulatory Commission notified draft regulations on Demand Response Regulations, 2024 on 3rd August, 2024. The objective of the draft are mentioned below:

Key Highlights:

- **Integration into Distribution Operations:** Incorporating Demand Respose (DR) into the daily activities of Distribution Licensees to enhance efficiency and asset utilization.
- **Load Management and Environmental Benefits:** Promote load shifting, reduce seasonal peaks, address power shortages, and lower greenhouse gas emissions.
- **Cost Efficiency:** Decrease reliance on short-term power procurement and lower overall electricity costs.
- **Dynamic Pricing:** Introduce Time-of-Use tariffs and other mechanisms to encourage energy-efficient consumption.
- **Network Security and Reliability:** Improve network security while ensuring a balance between electricity supply and demand also mitigate congestion in the distribution network.
- **Participation in Ancillary Services:** Enable consumers and aggregators to contribute to ancillary services through DR programs.
- **Renewable Energy Integration:** Facilitate the smooth integration of renewable energy sources and distributed generation into the grid.

EAL Opinion

Qualifying Criteria for Aggregators: In the proposed Clause 2.1(b) definition of the aggregator is given as *"Aggregator" is an entity registered with the Distribution Licensee to provide aggregation of one or more of the services like demand response services under the demand response mechanism, Distributed Generation, Energy Storage etc. within a control area;"*

The regulation mandates registration of the Aggregators with the Distribution Licensee (DL). There should be an online registration process for the same. The regulation should set clear qualifying criteria for the aggregator so as to avoid potential disputes.

The qualifying criteria may include the following:

- Minimum net worth
- At least one employee with technical background, especially qualified energy manager or, one with electrical engineering background with adequate training in regulatory aspects
- Adequate IT and metering capabilities for real-time monitoring
- Conflict of interest declaration – with reference to the relationship with employee of the DL and the entity managing power procurement on behalf of the DL[1]

The registration process including qualifying criteria, registration fee, registration timeline, conditions for revoking registration, reporting requirement including format thereof, format for application, dispute resolution mechanism, required IDs, certifications etc. Furthermore, **a compliance mechanism, especially in terms of reporting requirement,** should be clarified upfront and be strictly followed. Clarity on these aspects will ensure a transparent and efficient role of aggregators in the demand response program across the state.

All details for the registered aggregators along with key qualifying criteria and status of registration should be uploaded on the Distribution Licensee's website. **Report on monthly activities of the Aggregators should also be archived and accessible from the Distribution Licensee's web portal.**

Suggested Citation: Singh, A. (ed.). (2024), Opinion on AERC (Demand Response) Regulations, 2024 [Draft], In Power Chronicle (Vol. 07, Issue 03, pp. 26-29), Energy Analytics Lab (EAL), Indian Institute of Technology Kanpur.
https://eal.iitk.ac.in/assets/docs/power_chronicle_vol_7_issue_3.pdf

[1] This is ensure that selected aggregators are not unduly favoured by insider/advance information or in terms of deployment of DR services.

[2] A consumer may wish to switchover to another aggregator due to lack of sufficient incentives/revenue sharing or a dispute between the consumer and the existing aggregator.

- **Definition of Control Area:** In the proposed Clause 2.1(b) *"Aggregator" is an entity registered with the Distribution Licensee to provide aggregation of one or more of the services like demand response services under the **Demand Response Mechanism, Distributed Generation, Energy Storage etc. within a control area."*** (emphasis added)

  For a distribution licensee, a "Control Area" typically refers to a specific geographical region, often corresponding to district boundaries. It seems that the regulation may be referring to the licensee area rather than control area. If so, appropriate correction may be made.

- **Compliance Mechanism for Services Offered by the Aggregators:** The distribution licensee should also have a credible and effective compliance mechanism vis a vis the aggregators. In case of deviation from schedule, the suppliers of electricity face consequences under the Deviation Settlement Mechanism. Similarly, in case of the services offered by the aggregators, a compliance mechanism must be in place. This can be embedded as a part of the contractual agreement or be designed to be an integral part of the pricing/incentive mechanism.

  For instance, if a DL seeks 10 MW demand reduction during identified time blocks and the aggregator, who has committed to provide that service, falls short of its commitment. This has consequences in terms of higher cost, or unserved energy to consumers (in this case) and thus reduction in its standard of performance targets.

- **Ensuring Compliance by Third Party:** In the proposed Clause 3.2, *"The Licensees shall **ensure** that aggregator and or other third parties involved in demand response program **comply** with these Regulations through appropriate conditions in the respective contracts."* (emphasis added)

  Who are the 'other' third parties? Third party may include an IT service provider, an entity supplying/installing special meters, or the consumer (?) etc. The licensee may not be able to 'ensure' compliance with the provision of the regulations, but it can include a mechanism, with adequate penalty, to seek its compliance. However, this would also require that the regulation itself has a penal mechanism for non-compliance by the licensee.
  The compliance mechanism should include a reporting framework for the aggregators. This should be in line with the reporting framework to be prepared by the Commission for the licensee vis a vis services to be offered by the aggregators.

- **Pricing Mechanism for DR Services:** The regulations do not provide any guidance on the mechanism for pricing of DR services to be provided by the aggregators. While this would be a 'commercial' decision by the licensee, a guiding framework can help meet the objective of peak demand reduction in an economical manner. We suggest that, subject to an effective compliance mechanism, **compensation/pricing mechanism for DR services delivered by an aggregator should be linked to the prevailing market price** (i.e. short-term avoided cost for the distribution licensee). This would ensure that there are correct pricing signals for the distribution licensee as well as the aggregators.

  The DR mechanism should generate net savings in the power procurement cost. One third of additional saving, beyond the cost reduction under the demand response target, may be provided as an incentive to the distribution licensee. In its absence, compliance towards provision of DR services would be weakened. An incentive mechanism may also be put in place by the distribution licensee for consistent and reliable delivery of DR services by an aggregator.

- **'Market Access'– Locking up Consumers with an Aggregator:** An aggregator may need to installs metering and communication systems on the premises/equipment of, say, specific C&I consumers. To avoid lock-in of the consumer to a single aggregator[1], the regulation should provide for easy switchover by specifying a limit for removal of the existing metering/ communication system in a time bound manner, else the consumer should have the right to get it replaced by another aggregator's metering/communication system. In its absence, the market for DR services would be characterized by an 'entry barrier' thus reducing competition thereof.
  To ensure that the aggregators do not impose restrictive conditions or impeded/delay switchover to other aggregators, the regulation should ensure that such switchover is smooth and, if required, the communication/control equipment of the existing aggregator are either removed or handed over (as per pre-defined terms) to the consumer in a time bound manner. Clearly defining these terms and conditions is crucial to prevent potential disputes in the future.

Demand Response Target Setting: In the proposed Clause 6.2, *"The Commission shall review and establish DR targets based on DR potential assessed by the distribution licensees such as % reduction in overall demand, % reduction in peak demand, % reduction in peak demand in different seasons, % reduction in short term power procurement for DR, etc. within 3 months from submission of the DR potential assessment report by the distribution licensee."*

It is suggested that **target setting for the DR should be avoided in the very beginning** and such target setting should not just be based on post submission of a Detailed Project Report (DPR) but should consider **experience from a broad based DR pilot targeting various consumer categories.** The Commission should set a clear timeline for completion of DPR and pilot. In case of any delay in doing so, the Commission may proceed with setting a DR pilot thus ensuring that any laxity on this part does not lead to delay in setting DR target. **The target set should be measurable and have a compliance mechanism in place.** To ensure that there is overall economics in achieving those targets, it would be prudent to adopt an **overall DR target,** especially in terms of cost reduction through DR, and **avoid setting service-specific target,** unless required due to the differentiated services that does not have a common metrics of measurement. Some of the alternate targets may be on the basis of:

- Reduction in peak demand (in MW) – by demand reduction or through discharge of storage.
- Reduction in need for short-term power procurement.
- Saving in power procurement cost during deployment of DR.
- Avoided additional cost of new distribution assets/infrastructure[3].

Target setting for DR includes setting a baseline, this would require seamless collection of data by the Distribution Licensee and its analysis. Institutional mechanism should be put in place to ensure that such high frequency data is compiled across targeted consumers and is also available for research to estimate appropriate baseline and DR potential. A provision for the same be incorporated in this regulations.

DR Target and Resource Adequacy: CER pointed out in numerous submissions that DR can and should play a role in assessment of resource adequacy by the distribution licensees[4,5,6,7] . DR can help postponement of the capacity additional/capacity contracting, especially for thermal power generation and/or storage services thus economising on cost of power procurement.

To the extent that the distribution licensee would be able to reduce peak demand due to DR, it would result in lower resource adequacy requirement and, thus, should be reflected in **'updated' resource adequacy projections for the projection horizon.**

Timeline to assess Demand Response Potential: In the proposed Clause 6. *"Distribution licensees shall assess the DR potential before 9 months of the start of the control period and submit DR potential assessment report to the Commission;*

Provided that for the next control period (FY 2025-26 to FY 2027-28), the distribution licensees shall assess the DR potential for FY 2026-27 and FY 2027-28 within 6 months from the date of notification of these regulations and submit DR potential assessment report to the Commission."

Assessment of demand response potential is a time taking task and must also be accompanied with pilots to assess implementation challenges and address the same. It may be difficult to assess the DR potential in a short-period of 6 months as DR needs to access across the year. Being a first time initiative, the regulation should provide for adequate time for the first DPR on DR potential. If these regulations are notified within next 1 - 2 months, a period of 10 - 12 months may be provided for undertaking a meaningful assessment of demand response potential. Thorough analysis for a year, would allow the distribution licensee, to gather and analyse data across all the seasons throughout the year, enabling them to identify patterns, peak demand periods, and the specific scope for DR initiatives within their control areas.

Demand response is a relatively short-term strategy to ensure resource adequacy. Due to dynamic demand supply as well as market scenario, a reliable estimate of the DR potential may not be feasible on a multi-year ahead basis. DR potential depends on the load growth, flexibility with consumers, penetration of storage and efficient devices as well as incentive for DR. These can be assessed more reliably with a near-term horizon. **The regulation should thus provide for annual updating of the DR potential.**

Implementation of Pilot Demand Response programs: In the proposed Clause 9.5 *"The Distribution Licensee shall design, develop, and implement few pilot DR programs targeting different consumer categories having smart meter installed till the complete baseline data is available for its area of supply. Establishment of baseline data shall not be a pre-requisite for design of such initial pilot DR Programs by the Distribution Licensee."* **Setting baseline** for the underlying parameters, for example demand profile across a day (across months/seasons), is **the most important design aspect of a demand response program.** The regulation should provide a framework for setting the baseline. Furthermore, timeline for committing to demand response and its actual deployment also determines if the 'actual' reduction in demand has been achieved. **In case of a poorly designed baseline, and the deployment framework, the distribution licensee may likely be paying for ghost demand response.** It is essential that these pilot DR programs include a Cost-Benefit Analysis (CBA) to evaluate economic viability of the schemes. A thorough CBA will help in understanding not only the financial implications but also the potential benefits in terms of demand reduction, peak load management, cost reduction, avoided cost of infrastrcuture and overall grid stability. Furthermore, ongoing monitoring and evaluation of the pilot programs will be crucial for refining the DR initiatives based on actual performance data. This process will enable DISCOMs to adjust their strategies and enhance the effectiveness of future DR programs. **Report of the pilot programs as well as annual performance of aggregators should be available in public domain for stakeholder knowledge and feedback.** This would also the knowledgebase for DR implementation across the country.

[3] This is difficult to measure and may be a long-term objective, rather than a specific target.
[4] Singh et al. (2019), Regulatory Framework for Long-term Demand Forecasting and Power Procurement Planning, CER Monograph, Book ISBN:978-93-5321-969-7, https://cer.iitk.ac.in/assets/downloads/CER_Monograph.pdf
[5] Detailed studies have been undertaken for the states of Uttar Pradesh and Chhattisgarh, incorporating long-term demand forecasting as well as power procurement panning.
[6] TNERC(Framework for Resource Adequacy) Regulations, 2024 [Draft], 2024, https://cer.iitk.ac.in/blog/new_blog/?id=MjU1OQ==
[7] CEA: Draft Guidelines for Resource Adequacy Planning Framework for India, 2023 (PC-5(3) of 2023), https://cer.iitk.ac.in/blog/new_blog/?id=MTg2NA==

EAL News

Capacity Building Programme for LDCs on "Regulatory and Policy Framework in the Indian Power Sector: Load Despatchers Perspective"

CER, in collaboration with Grid-India, conducted a Capacity Building Programme for Load Despatch Center on **"Regulatory and Policy Framework in the Indian Power Sector: Load Despatchers Perspective"** from 11^{th} to 13^{th} December 2024. Hosted under the aegis of the Center for Energy Regulation, Department of Management Sciences, IIT Kanpur. The inaugural session was honoured by the presence of Mr. S. R. Narasimhan (Chairman and Managing Director, Grid-India). The key speakers in the program were Mr. Subhendu Mukherjee (Deputy General Manager, Grid-India), Mr. Ravi Seth (Vice President of Business Development, IEX), Mr. Rajiv Porwal (Director System Operation, Grid-India), Ms. Ammi Ruhama Toppo (Chief Engineer (IRP-I), CEA), Ms. Shilpa Agarwal (Joint Chief (Engg.), CERC), Dr. S. K. Chatterjee (Chief Regulatory Affairs, CERC), Mr. Mukesh Kumar (Assistant Chief (Engg.), CERC, Dr. Balaraman Kannan (Executive Director, Idam Infrastructure Advisory Pvt. Ltd.), and Prof. Anoop Singh (Founder and Coordinator, CER and EAL, IIT Kanpur). The program aimed to enhance participants, understanding of the evolving regulatory and policy framework in the Indian power sector from a load despatchers perspective. It also provided a platform to knowledge exchange, learning about best practices, and engagement with leading Sector experts.

Mr. Jishnu Barua (Chairperson, CERC), chief guest to the valedictory functions, handed over certificate to the participants and provided insights on regulatory and policy framework in the Indian power sector.

Regulatory Certification Programme on "Power Market Economics and Operation"

CER, in association with EAL conducted the Regulatory Certification Program titled **"Power Market Economics and Operation"** from 6^{th} to 22^{nd} December 2024. This program was conducted under the aegis of the Centre for Continuing Education, IIT Kanpur. The program aimed at conceptual understanding into the economic operation, regulatory structure of power market, power procurement planning and strategy of power market, ancillary services and perspectives opportunity to learn best practices from experts. The key speakers in the program were as Mr. Akhilesh Awasthy (Partner, Lantau Group India Pvt. Ltd.), Mr. Ghanshyam Prasad (Chairperson, CEA), Mr. Samir Chandra Saxena (Director Market Operation, Grid-India), Ms. Shilpa Agarwal (Joint Chief (Engg.) CERC), Prof. Anoop Singh (Founder & Coordinator, CER & EAL, IIT Kanpur), amongst many more.

Mr. Ramesh Babu Veeravalli (Member, CERC), chief guest to the valedictory functions, handed over certificate to the participants and emphasized on contribution of informed decision-making and the advancement of regulatory frameworks in the power sector.

We request your feedback for making EAL and this periodical more relevant to the sector.
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Other Initiatives

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