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Power Chronicle

A Perspective on Kerala's Resource Adequacy Framework

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Editorial

The basic tenet of resource adequacy is to ensure that adequate resources are tied up to meet the short- to long-term electricity demand. While the prevailing framework is primarily focused on obligating the distribution licensees to tie up such resources. The captive consumers as well as open access consumers should also be mandated to ensure that adequate resources are tied up to meet their requirements. Increasing reliance on pure energy market not only enhances market volatility but also lacks incentive for capacity creation in future.

The resource adequacy plans (RAP) by the DISCOMs remain exposed to demand-supply mismatch from those forecasted and planned for. Short-term capacity market can offer a platform for rebalancing the tied up portfolio resources. This would also enable captive and open access consumers to comply with resource adequacy requirements instead of entering long-term PPAs.

Grid security is a joint responsibility of the constituent load and corresponding generation resources. The spinning reserve requirements should thus be mandated for all the grid participating load which have a tied-up capacity. This can also be facilitated through a 'market mechanism' for spinning reserve thus improving cost economics.

As per the CEA Capacity Credit Concept Paper, the capacity credit (thermal availability) for coal-based generation is assumed to be in the range of 0.7–0.8. Analysis shows that peak demand months' witness much higher capacity availability, often exceeding 95% as planned maintenance is scheduled in low demand months. A generalized average assumption of availability across the year results in overestimate of the required resources for peak demand period. This has cost consequences for the DISCOMs. A DISCOMs specific analysis should be carried out to ascertain such availability considering reasons for lower availability, technology vintage, past planned maintenance, breakdowns etc.

Demand-side resources can provide cost-effective alternatives to long-term capacity tie-ups, particularly during short peak periods. Recognizing demand response as a formal adequacy resource would also enhance system flexibility and reduce procurement costs. Demand response is a low hanging fruit that hasn't received its due attention for resource adequacy planning while also addressing short-term demand-supply mismatch thus avoiding costly power purchase agreements. This can also help address market volatility as consumers' load can be reduced through active demand management It is noted that demand spikes periods are very limited and such extreme demand may often be witnessed for a few hours during peak demand months. This often leads to rush for market-based procurement leading to the market prices hitting a cap.

Anoop Singh (Editor)
Founder & Coordinator, Energy Analytics Lab

Keywords: Resource Adequacy, Planning Reserve Margin, Demand Forecasting, Generation Planning, Power Procurement, Peak Demand, Capacity Credit, Loss of Load Probability, Energy Not Served, Renewable Energy Integration, Energy Storage, and Demand Response.

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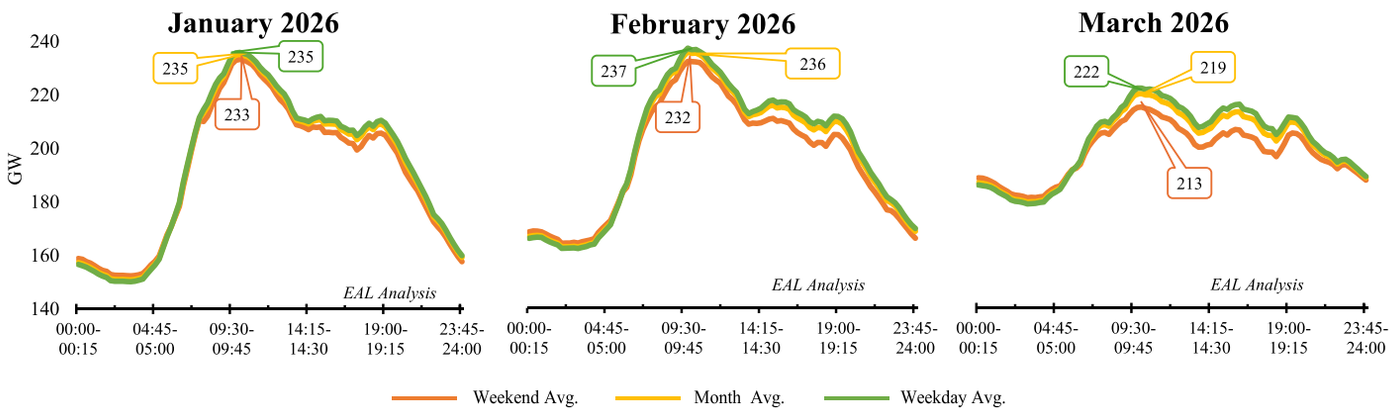
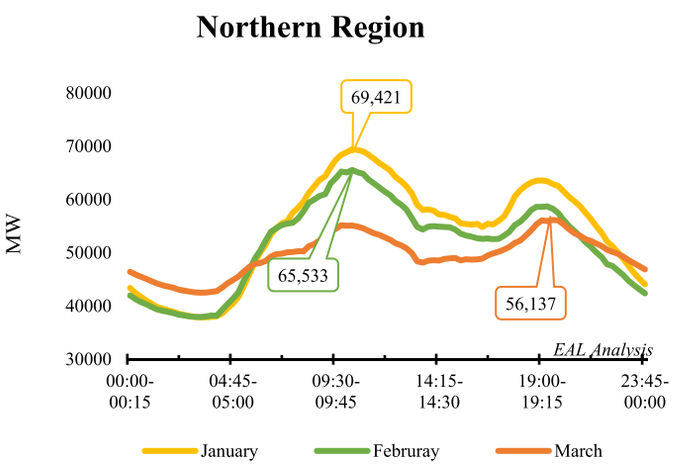
Power System Overview & Analysis

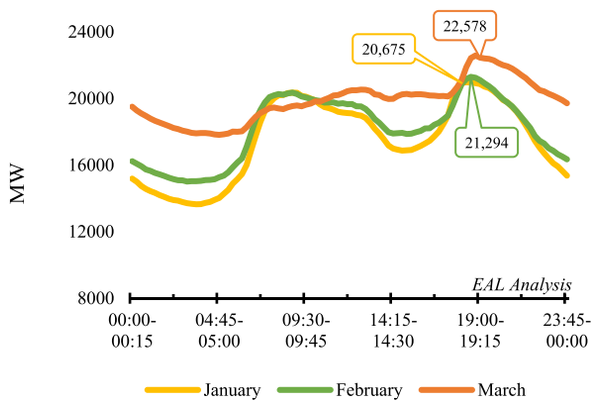
All India Demand Met Profile

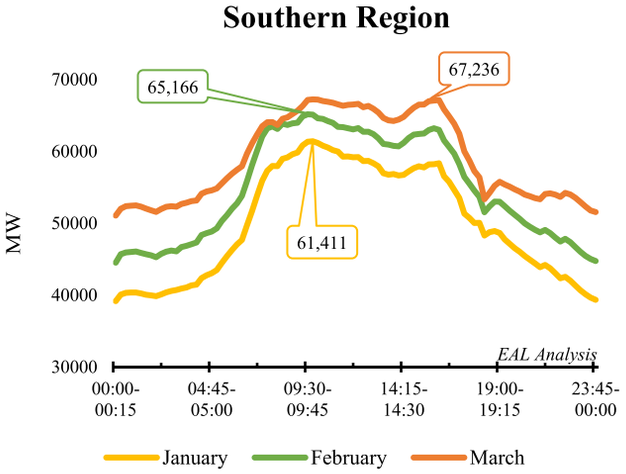


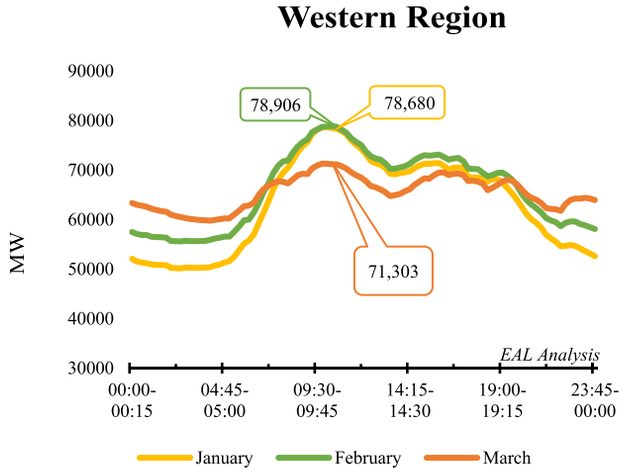
From January to March quarter, all India peak demand reached 243 GW (10:00 - 10:15) on 13th February, 2026, about 2.1% higher than the previous year's peak demand recorded at 238 GW (10:15 - 10:30) on 7th February, 2025, during the same quarter.

Region-wise Demand Met Profile

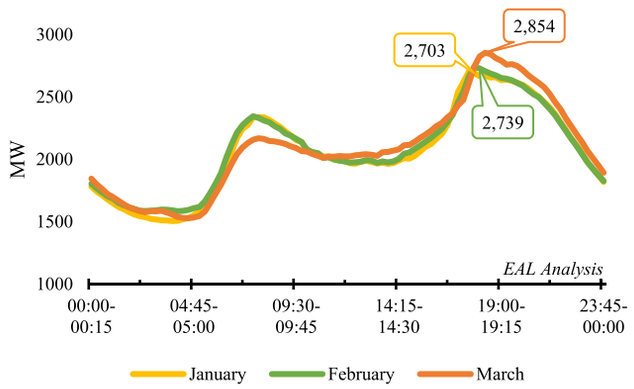








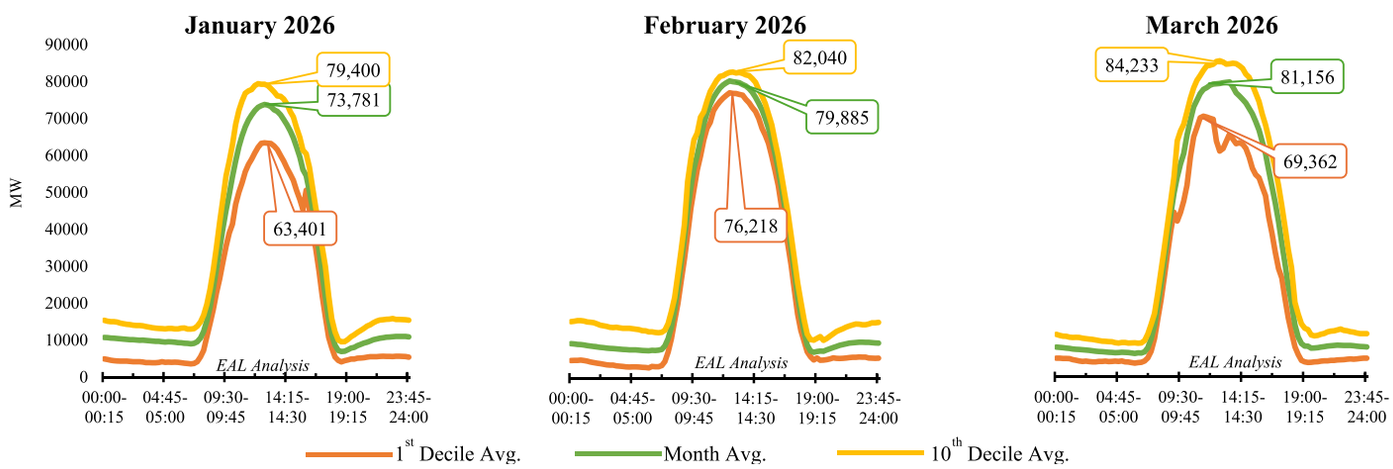
North Eastern Region



- Significant increase in demand can be observed for Northern, Southern, Western, Eastern and North Eastern and Southern regions from 04:45 to 07:30 hrs in all three months respectively.
- Decrease in demand can be observed for Northern, Southern, Western, Eastern and North Eastern and Southern regions from 19:00 to 23:45 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 February.

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

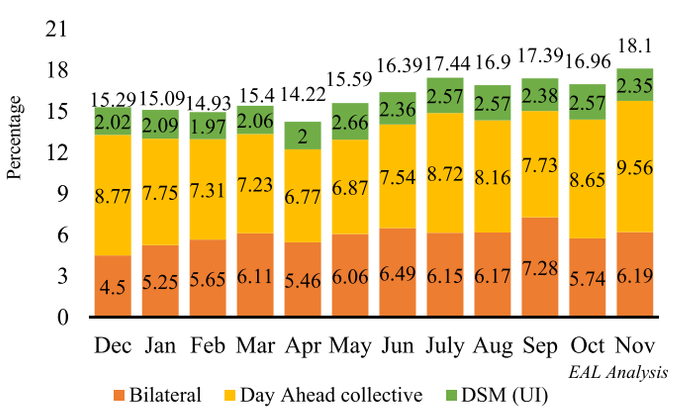
All India Renewable Energy Generation Profile



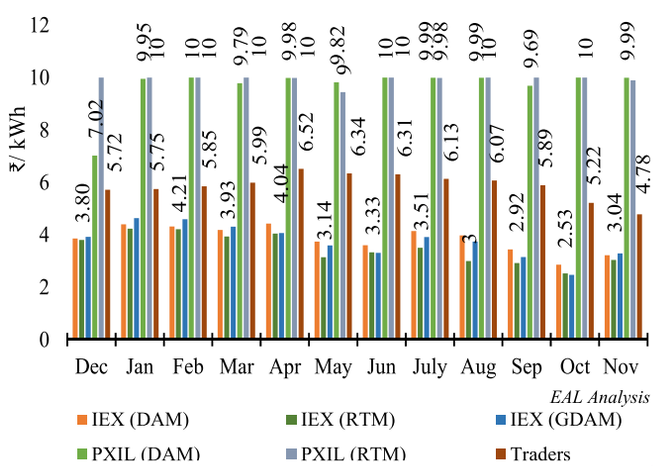
All India peak RE generation reached 84.50 GW (12:15 - 12:30) on 11th February, 2026, about 15.59% higher than the previous years' peak of 73.10 GW (13:15 - 13:30) on 6th February, 2025, during the same quarter.

Short-term Energy Transactions

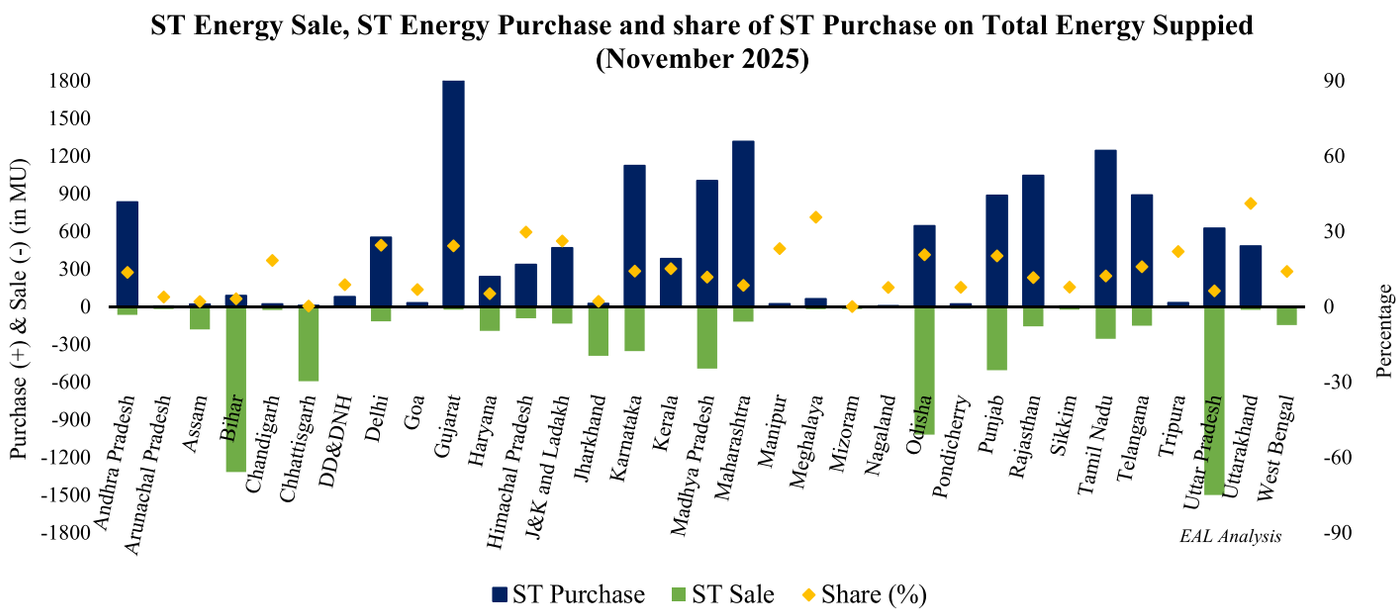
Share of Short-term Energy Transaction of Total Electricity Generation (Dec 2024-Nov 2025)



Weighted Average Prices of Short-term Transactions (Dec 2024- Nov 2025)

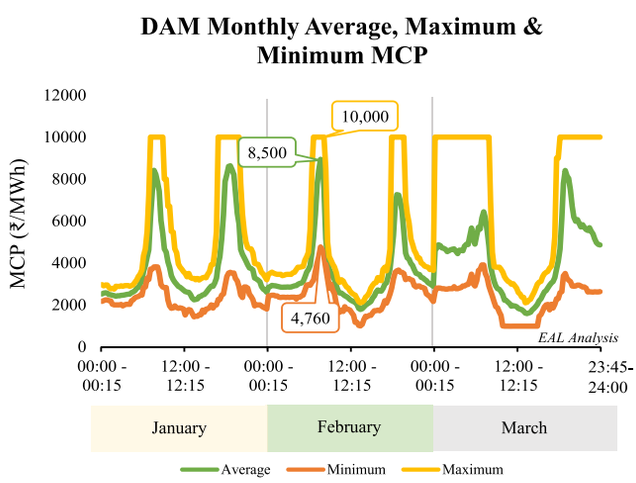


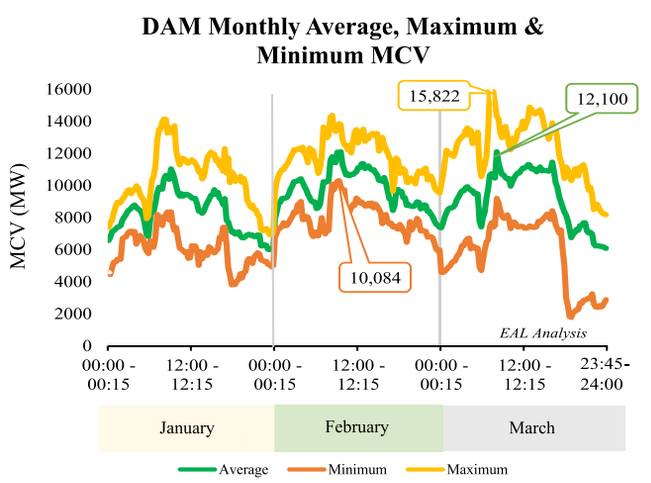
Monthly Power Purchase and Sale Quantum through Power Exchange across States



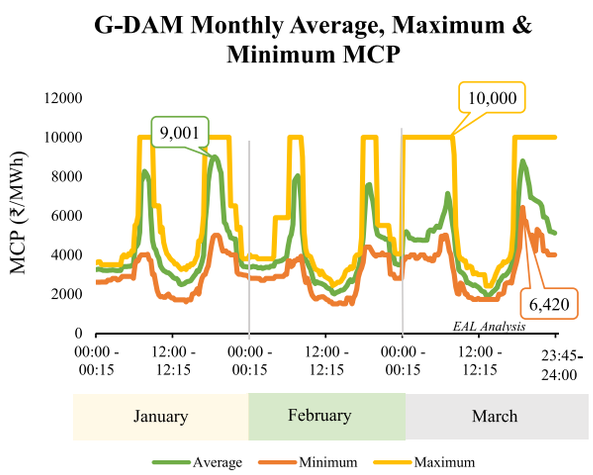
Power Market Overview & Analysis

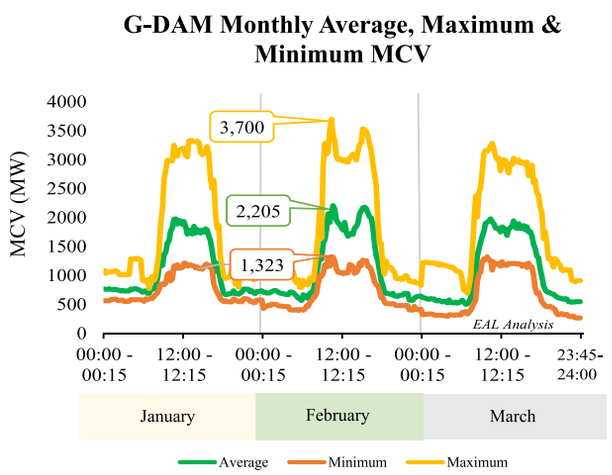
DAM - Market Clearing Price (MCP) & Market Clearing Volume (MCV)





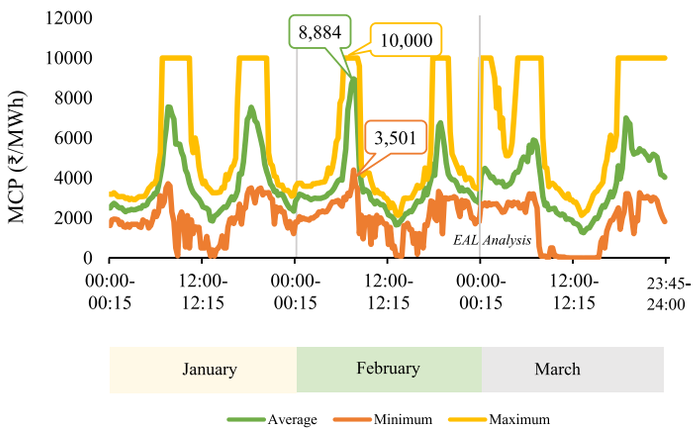
G-DAM- Market Clearing Price (MCP) & Market Clearing Volume (MCV)



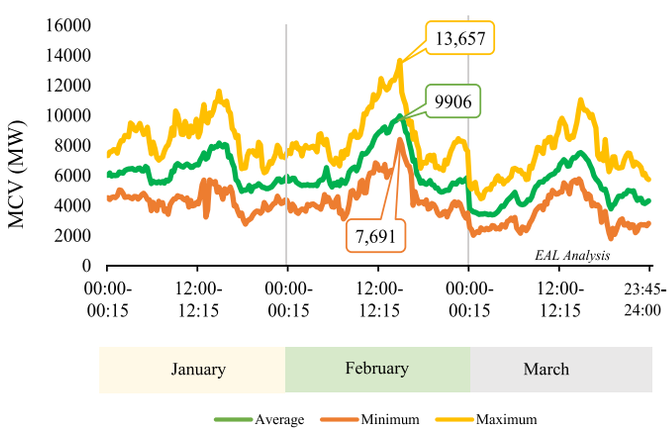


RTM -Market Clearing Price (MCP) & Market Clearing Volume (MCV)

RTM Monthly Average, Maximum & Minimum MCP

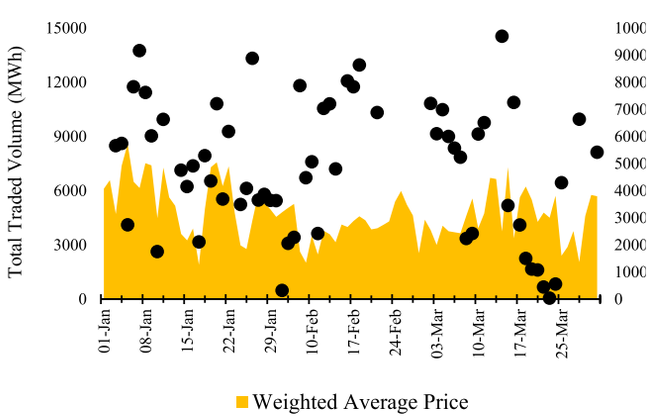


RTM Monthly Average, Maximum & Minimum MCV



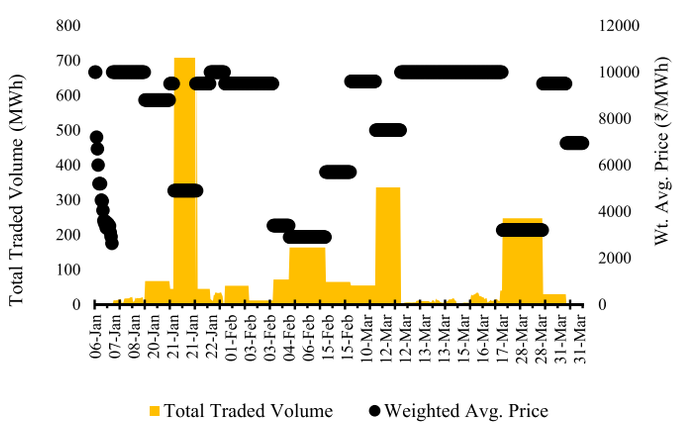
Term-Ahead Market

Day Ahead Contingency (Jan-Mar 2026)



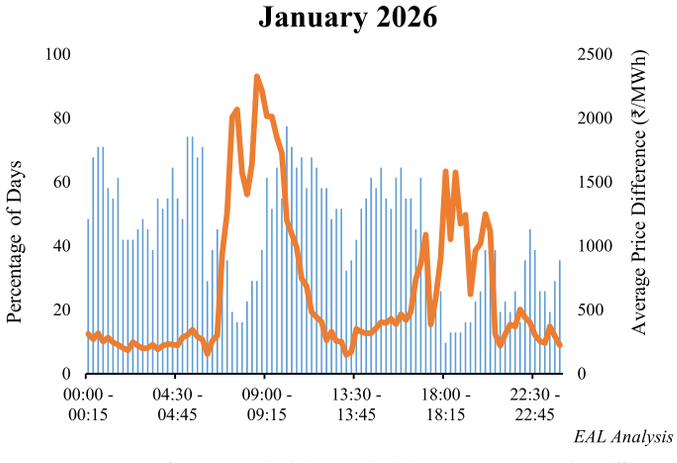
Green Term-Ahead Market

Daily Contracts (Jan-Mar 2026)

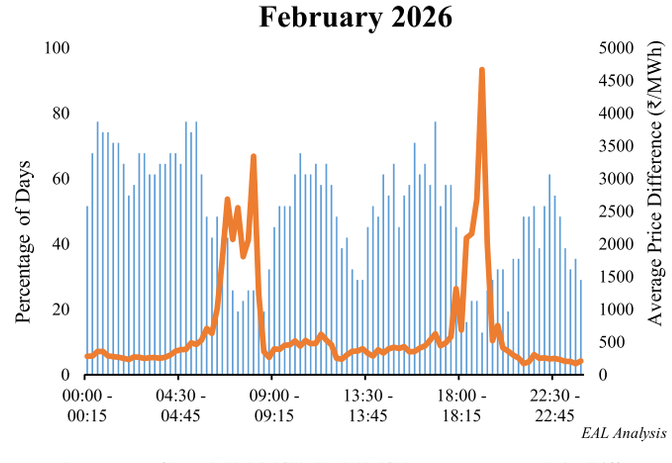


Price Difference between RTM & DAM

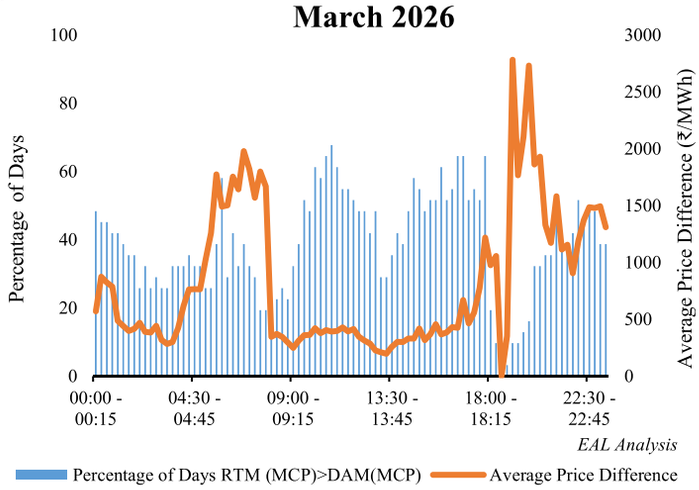
January 2026



February 2026



March 2026

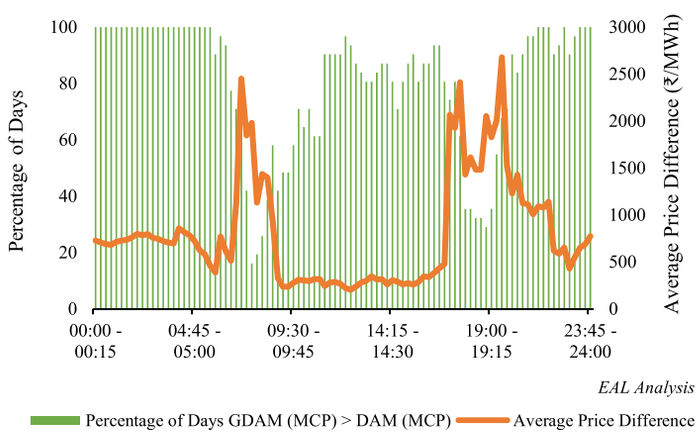


EAL Analysis

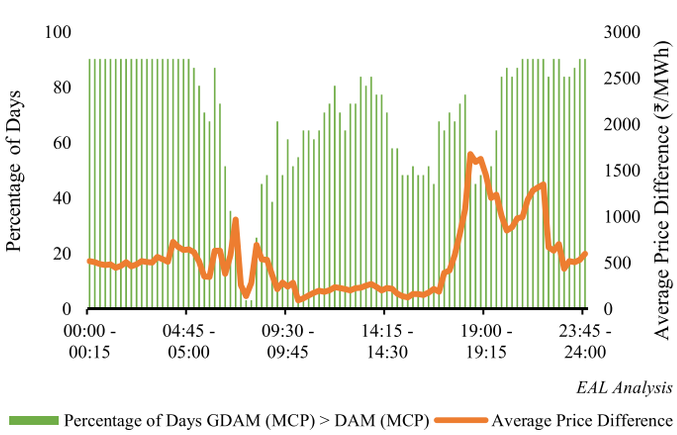
- The analysis is based on comparison between the average price difference of RTM and DAM, when MCP of RTM is greater than DAM for the fourth quarter of FY 2025-26.
- The graph shows the percentage of days, price for RTM is greater than DAM on the primary axis and the average price difference between the two on secondary axis.
- It has been observed that in 19:00-19:15 the highest average price difference is observed of Rs. 4.67/ kWh for the month of February, 2026.
- The average price difference between RTM and DAM is Rs. 0.71/ kWh for the quarter.

Price Difference between GDAM vs DAM

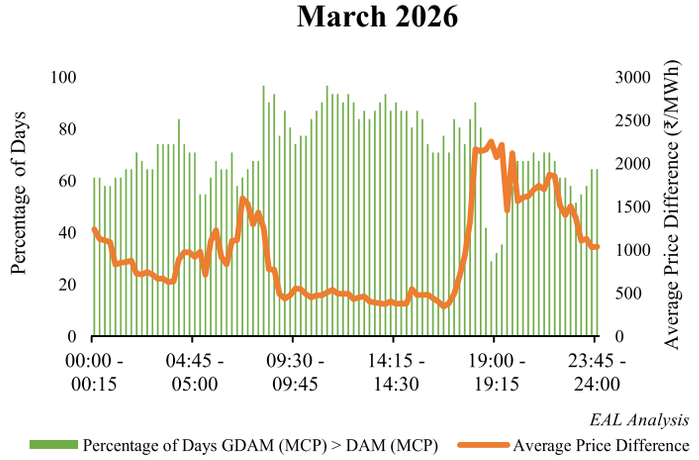
January 2026



February 2026



March 2026



EAL Analysis

- The analysis is based on comparison between the average price difference of G-DAM and DAM, when MCP of RTM is greater than DAM for the fourth quarter of FY 2025-26.
- 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.
- It has been observed that in 19:30–19:45 the highest average price difference is observed of Rs. 2.68/kWh for the month of January 2026.
- The average price difference between G-DAM and DAM is observed to be Rs. 0.78/ kWh for the quarter.

Opinion on KSERC (Framework for Resource Adequacy) Regulations, 2026

Cite

The KSERC notified a draft on "Framework for Resource Adequacy, Regulations", on 4th February, 2026. The main objectives of the draft are given below:

Objective: These regulations aim to facilitate the implementation of a Resource Adequacy framework by establishing a systematic approach for planning generation resources to reliably meet the projected electricity demand in accordance with specified reliability standards, while ensuring an optimal generation mix. The framework also includes provisions for demand assessment and forecasting, generation resource planning, procurement planning, as well as monitoring and compliance mechanisms.

EAL Opinion

- **Importance of Resource Adequacy Framework**: India's electricity sector is experiencing sustained demand growth alongside accelerated renewable integration, intensifying the challenge of maintaining a reliable demand-supply balance, particularly during peak demand periods and extreme weather events. This transition requires a shift toward structured, forward-looking resource planning mechanisms. Utilities must secure adequate firm and flexible capacity, strengthen demand response, incorporate energy storage systems, and leveraging inter-state and intra-state power exchange efficiently.

  The overarching aim of the Resource Adequacy (RA) framework is to ensure a demand-supply balance while safeguarding system security and reliability at the national level. An RA study seeks to optimize power procurement in a cost-effective manner while ensuring that prescribed reliability standards are met. As power procurement plans are to be decided in advance, these must be developed proactively on the basis of credible and analytically robust demand forecasts. In this context, Centre for Energy Regulation, IIT Kanpur has underscored the necessity of a structured regulatory framework for RA planning[2]. CER and EAL IITK have also provided inputs on related regulatory matters[3], including the "Power Purchase and Procurement Process Regulations"[4], and the "Terms and Conditions for short-term procurement/sale of power Regulation, 2021"[5].

  Given the experience of CER and EAL in carrying out Long-term Demand Forecasting and Power Procurement Planning for the states of Uttar Pradesh and Chhattisgarh, we reinforce the need for a robust regulatory framework for the same. **From these studies, it was inferred that significant economic benefits in terms of reduced private and social costs are possible through RA.**

- **DISCOMS Responsibility to Meet System load or Contracted Demand of its Consumers:** The obligation of a DISCOM is limited to meeting the requirements of its consumers, excluding consumers who procure power through captive generation or open access. Imposing an obligation on the distribution licensee to account for the entire system load would place an undue burden on the DISCOM to arrange capacity for demand that it neither commercially serves nor is required to serve. It is evident that the regulations do not intend to create such

[1]Suggested Citation: Singh A. (ed.). (2026), Opinion on KSERC (Framework for Resource Adequacy) Regulations, 2026, Power Chronicle (Vol. 08, Issue 04, pp 7-24), Energy Analytics Lab (EAL), Indian Institute of Technology Kanpur. https://eal.iitk.ac.in/assets/docs/power_chronicle_vol_8_issue_4.pdf

[2]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

[3]Detailed studies have been undertaken for the states of Uttar Pradesh and Chhattisgarh, incorporating long-term demand forecasting as well as power procurement planning. Furthermore, demand forecasting was carried out for the DISCOMs of Rajasthan, and, a long-term demand forecast was done for incorporation in a study on RE integration for the state of Gujarat.

[4]Draft Detailed Procedure for Madhya Pradesh Electricity Regulatory Commission (Power Purchase and Procurement Process) Regulations, Revision-II, 2022 (RG-19(2) of 2022), https://cer.iitk.ac.in/odf_assets/upload_files/blog/Revision_2_2022_Power_Procurement_Draft_Regulation.pdf[6]

[5]APERC (Terms and Conditions for short-term procurement/sale of power) Regulation, 2021, https://cer.iitk.ac.in/odf_assets/upload_files/Draft_APERC_Terms_and_Conditions_for_short_term_procurement_sale_of_power_Regulation_2021.pdf

duplication of responsibility. Consumers with captive generation arrangements would continue to rely on their own generating resources or contractual tie-ups.

For example, if a DISCOM supplies (say) 6000 MW within a State where the total connected demand is (say) 8,000 MW (including captive and open access consumers), the DISCOM should be required to maintain reserve margins only against its supply obligation. Requiring reserve margins for the full 2,000 MW would result in the DISCOM's consumers bearing the cost of capacity procured to serve demand for which the DISCOM has no supply obligation. **From a system's point of view, the captive generators should be equally responsible for keeping reserve**, which may be harnessed by the system operator through an appropriate mechanism. The associated cost is thus shared by the consumers of the DISCOM as well those with their own captive generation.

However, ambiguity arises due to the use of the term "system load" in several definitional provisions of the Draft RA Regulations, particularly Clauses 4(j), 4(m), 4(n), and 12.2, as reproduced below:

" (j) "Loss of Load Probability" or "LOLP" means probability that a system's load will exceed the generation and firm power contracts available to meet that load in a year.

(m) "Normalized Energy Not Served" or "NENS" is normalization of the EENS by dividing it by the total system load.

(n) "Planning Reserve Margin" or "PRM" means a certain percentage of peak load forecast of the system, required for conforming to the reliable supply targets specified by the Authority/Commission from time to time."

Clause 12.2 "*A loss of load occurs when the system load exceeds available capacity in a particular time. Appropriate LOLP / NENS metrics should be considered based on consultation with stakeholders and international best practices*."

These definitions are anchored to the concept of system load referring to the total electricity demand within the state system, without distinguishing between demand served by the DISCOM and demand met through captive generation or open access. As per the proposed definitions, the DISCOM remains responsible to provide for planning as well as spinning reserves for the state as a whole, even if a part of that load is being met by captive consumers through their own generation or resources located in or outside the state. In case of a captive consumer being served by a generating capacity located outside the state, the burden of planning reserve as well as spinning reserve should not be placed on the DISCOM, and hence the consumers of the discom. A fairer and equitable approach would be to allocate the responsibility of planning and spinning reserve on captive consumers as well. This should also ensure similar compliance mechanism as in the case of DISCOM.

To ensure the suggested regulatory consistency, the definitions with 'system load' anchoring may be modified to allude to calculation of for e.g. overall system reserve or LOLP/NENS, while ensuring that the reasonability for compliance thereof is fully allocated to the DISCOM and the captive consumers as suggested above.

- **Moving towards Methodological Consistency in Reliability Assessment and Treatment of Uncertainty:** The proposed draft provision under Clause 12.4 and 12.5 "*address Methodological Consistency in Reliability Assessment and Treatment of Uncertainty."*

  If reliability indices such as LOLP and NENS are being adopted, the assessment thereof is already grounded in a probabilistic framework. These indices inherently account for uncertainty through probabilistic modelling. Introducing Monte Carlo simulation as an additional and separate requirement effectively duplicates the task of incorporating uncertainty.

  Uncertainty should ideally be modeled through a single coherent framework rather than layering multiple uncertainty treatments within same the assessments. Reliability should be assessed either through probabilistic indices such as LOLP/NENS or through scenario-based methods. Undertaking both approaches together may create methodological overlap, and the computational burden would also increase substantially.

National vs Discom-level Planning Reserve Margin (PRM)[6]: The approach to estimate national PRM, as per proposed methodologies in the RA Guidelines, must explicitly account for the uncertainties associated with both demand and supply-side variations. 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 1). **A uniform PRM of 5% across DISCOMs, in this example, could result in higher effective PRM at the national level. Aiming to achieve the same uniformly at the state-level may therefore impose high-cost incidence for the DISCOMs and, consequently, 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 may not necessarily need to be set as high as 5%. The example depicted in Figure 1 highlights that 'reserve' requirement for DISCOM A, whose peak demand does not coincide with the national peak, may be served by the reserve and the surplus capacity available with DISCOM B. This does not mean to suggest that DISCOM A should not make provision for reserves to meet its own peak. This highlights that the reserve requirement for DISCOM A can be substantially lower than a uniform yardstick of, say 5%, at the national level.

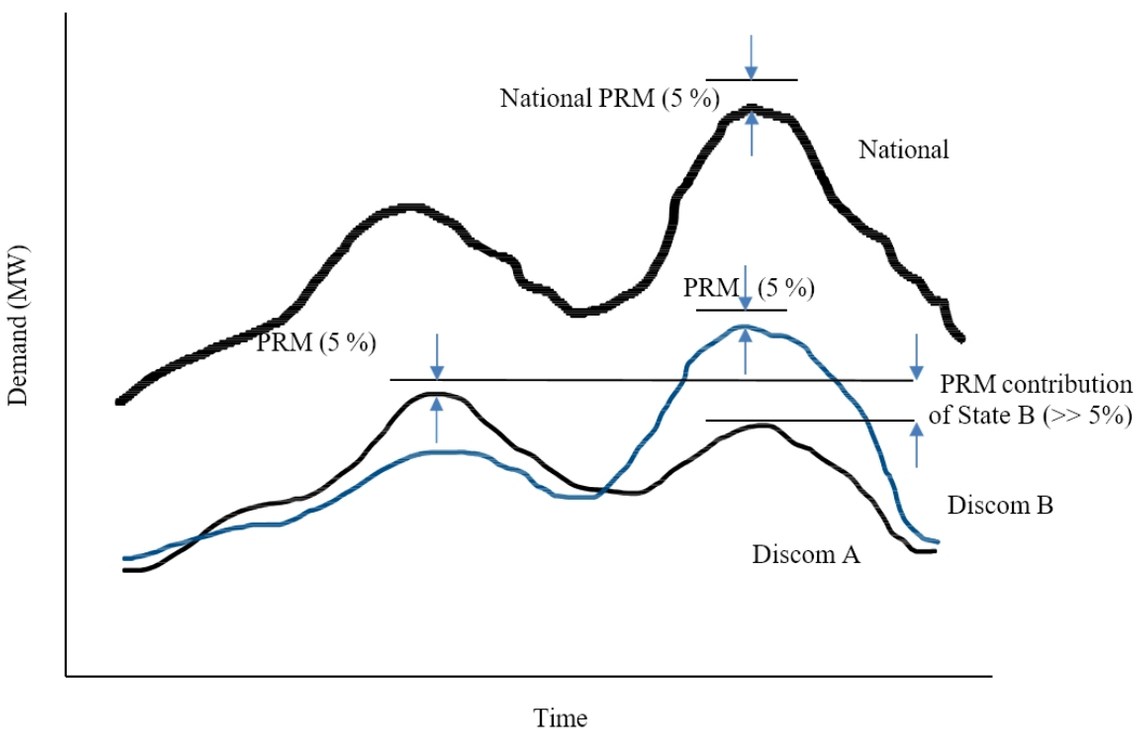


Figure 1: National Vs DISCOM level PRM

The key issue is whether a PRM of 5% at the national level implies that the PRM at the State level must necessarily be lower than 5%. The State-level PRM can be derived based on each State's contribution to the national peak demand. Essentially, the methodology would require analyzing each State's peak demand and its coincidence with the national peak. Based on this relationship i.e., the State's own peak versus its coincident peak with the national system appropriate weightages can be assigned. This simplified approach allows us to estimate how much PRM is actually achieved at the time of the national peak.

[6]Singh et al. (2024), CEA Draft discussion paper on "Methodology for Capacity Credit of Generation Resources & Coincident Peak Requirement of Utilities under Resource Adequacy Framework, 2024 [Draft], Power Chronicle (Vol. 07, Issue 03, pp 20-21), Energy Analytics Lab (EAL), Indian Institute of Technology Kanpur. https://eal.iitk.ac.in/assets/docs/power_chornical_vol_7_issue_3.pdf

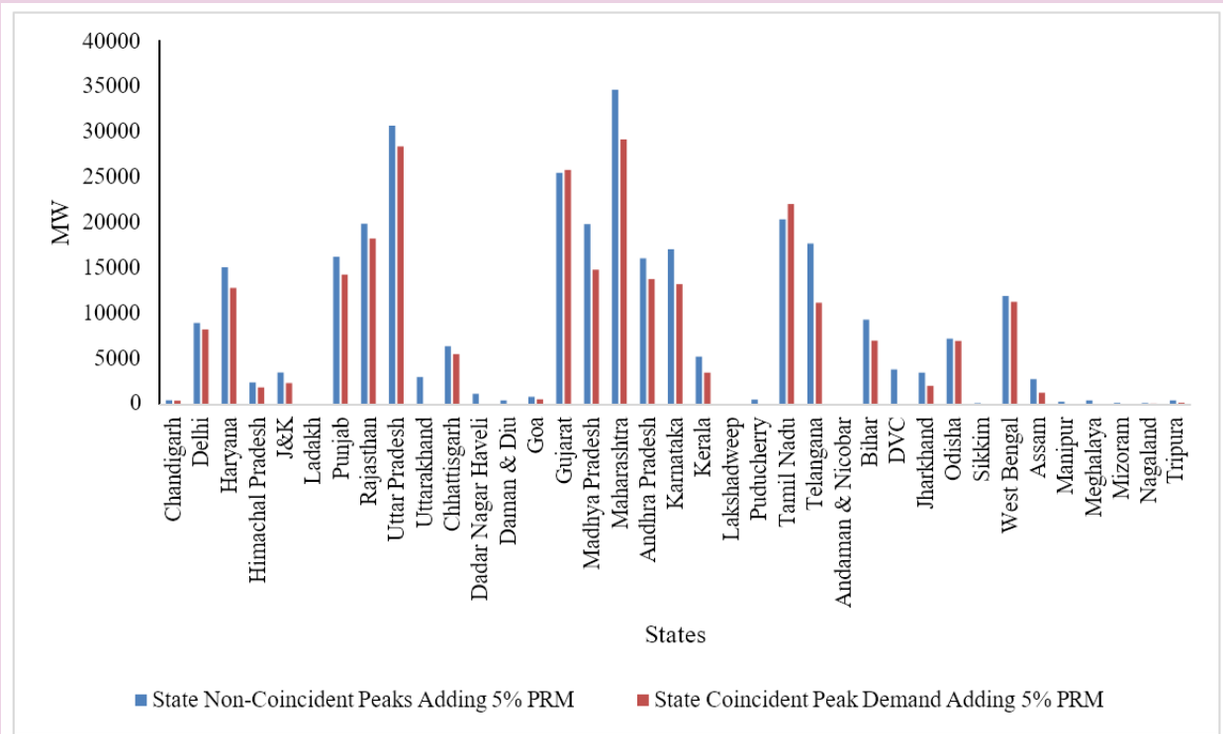


Figure 2. Impact of Uniform 5% PRM on State coincident and state non-coincident peak demand (FY 2024–25)

Table 1: National Coincident Peak and State non-coincident peak demand

Particulars	Demand (GW)	Capacity with PRM	Reserve (GW)
Sum of State Non-Coincident Peaks + 5% PRM	293	307	15
National Coincident Peak + 5% PRM	244	256	12

The estimates presented in Table 1 show that national level PRM would be estimated to be lower by about 5 GW if state level PRM is accounted for the respective non-coincidental peak of the states. **Thus, the decision of the DISCOM and the Commission's approval regarding PRM should account for such synergy in available PRM across states.**

It is recommended that corresponding to a national-level spinning reserve of 5% during national peak demand, may translate into lower than 5% spinning reserve requirement at the state level. This would provide a more realistic reserve estimation, preventing over-allocation of capacity atthe state level, while supporting efficient use of available generation for maintaining system reliability.

- **Guidance for State-Level PRM:** Proposed Clause 9.1 (a) states "*Planning Reserve Margin **as prescribed by CEA (National Level PRM) or** such **higher planning reserve margin determined** by the **distribution licensee**, subject to maximum limit of optimal PRM and **approved/ or specified** by the **Commission (State Level PRM).**"*

  Proposed Clause 9.3 (a) states "*The Resource Adequacy Requirement (RAR) constraint shall ensure that the total Resource Adequacy (Generation capacity) of the distribution licensee fulfils the Planning Reserve Margin **as determined by the Authority (National level PRM)** and **approved by the Commission.***

  Proposed Clause 11.4 (d) states *"**Distribution licensee** is free to consider **higher planning reserve margins** as defined under 'State Level PRM' in Clause 4.1 of these Regulations, subject to approval from the Commission." (emphasis added)*

  The present draft Clauses raise the need for three key clarifications with respect to the determination of PRM.

1) First, clarification is required on the applicability of the prescribed maximum limit. It is unclear whether this maximum limit applies:

   - only to the PRM proposed by the distribution licensee (DISCOM)
   - or both to the PRM proposed by the DISCOM and the PRM specified by the Central Electricity Authority (CEA)

   This distinction is critical and requires explicit clarification.

2) Second, the current wording may lead to conflicting interpretations. For example, if the CEA specifies a PRM of 5%, the DISCOM proposes a PRM of 6%, and the Commission prescribes an upper limit of 4%, it is unclear which value would prevail Planning reserve margin as per Clause 9.3 (a), as currently drafted, and that as per Clause 9.1 (a), are not in consonance with each other. While Clause 9.1 refers to 'prescribed' PRM by CEA, Clause 9.3 refers to that determined by CEA. The regulation should ensure coherence in terms of 'determined'/'prescribed' level of PRM and any limit thereof.

   Proposed Clause 9.1 (a) and 9.3 (a) may be rephrased as to maintain coherence with the CEA guidelines as following:

   "*Planning Reserve Margin as prescribed by CEA (National Level PRM) or such higher planning reserve margin determined by the distribution licensee, subject to maximum limit of optimal PRM and* ***as*** *approved/ or specified by the Commission (State Level PRM).*"

   Proposed Clause 9.3 (a) should be rephrased as "*The Resource Adequacy Requirement (RAR) constraint shall ensure that the total Resource Adequacy (Generation capacity) of the distribution licensee fulfils the Planning Reserve Margin* ***as approved by theCommission.***

3) **Value of Lost Load (VoLL):** It is an intrinsic value attached to the unavailability of electricity and should be estimated on the basis of structured methodology. The Value of Lost Load is typically derived at the point where the marginal cost of supply equals the marginal cost of unserved energy. Therefore, **a separate and detailed analytical exercise should be undertaken estimate Value of Lost Load. The cost of unserved energy may be derived on the basis of alternate methods including**

   (i) **Contingent valuation approach**

   (ii) **Assessment of the economic and social costs of load loss across different consumer categories.**

- **Procurement Obligation and Demonstration of Resource Tie-up:** Proposed Clause 11.3 states *"Based on the share in national peak provided in LT-NRAP, distribution licensee shall* ***plan to contract*** *the capacities (peak contribution * (1+National level PRM)) to meet their Resource Adequacy Requirement (RAR) at the time of national peak. The distribution licensee shall* ***demonstrate*** *to the Commission 100% tie-up for the first year and a minimum 90% tie-up for the second year to meet the requirement of their contribution towards meeting national peak. Only* ***resources with long / medium / short-term contracts*** *shall be considered to contribute to the RAR." (emphasis added).*

  As a general guidance, the share ***of long-term contracts*** *including own generation is to be in the range of 75-80% of the total supply side RAR. The medium–term* ***contracts*** *may be in the range of 10% - 20% of the total supply side RAR while the rest can be met through short-term contracts. Power procurement through the power exchanges, such as the Day-Ahead Market segment, shall not be considered to contribute to RAR. However, these ratios of long-, medium-and short-term* ***contracts*** *may be reviewed periodically by the Commission based on further experience.*"

  Clause 11.5 states "The Distribution licensee, through the LT-DRAP, shall also ***demonstrate*** *to the Commission,* ***arrangements*** *to meet at least 100% and 90% of their peak demand and energy requirement for the first year and second year respectively, subject to adequately addressing the demand and supply variations/to meet the prescribed standard of LOLP/NENS conditions as stipulated by the Authority/Commission from time to time, with a*

*mix of **long-term, medium-term and short-term contracts, including power exchanges**.*

*Provided that, the Distribution licensee shall **demonstrate** to the Commission, the resource mix to meet 100% of the requirement of peak demand and energy requirement for the **entire control period** for which application for determination of retail supply tariff shall be made before the Commission, subject to other constraints in meeting the peak demand and energy requirement." (emphasis added).*

Clauses 11.3 and 11.5 lays down procurement obligation of power procurement for the next two years and does not spell out the obligation beyond that. The provision to Clause 11.5 refersto obligation across the tariff control period, which may extend up to five years. Obligation for such procurement needs to be clearly laid out in the regulation. The level of obligation in terms of percentage of requirement of peak demand for third year onwards need to be spelled out in the regulation.

Uncertainty of Compliance for the Entire Control Period: For compliance towards meeting the RA obligation beyond two years, the distribution licensee would be able to 'demonstrate' tie-ups of long-term and medium-term nature only as short-term contracts would generally be signed up to 1 year in advance. However, procurement portfolios are dynamic and evolve over time in response to changes in demand, market conditions, and regulatory requirements. The contractual mix cannot be conclusively determined or demonstrated for several future years/ entire control period at a single point in time. The regulation should provide adequate flexibility in terms of level of compliance beyond two-year horizon.

- **"Plan to Contract" vs "Demonstrate":** Clause 11.3 provides ambiguous guidance for the mandate for RA as it refers to 'plan to contract' as well as the need to 'demonstrate'. Clause 11.5 refers to 'arrangements. regulation should provide unambiguous mandate for RA in terms of firmness of contract and the available flexibility as the distribution licensee plans to procure power for future RA needs.

These interpretations have materially different regulatory and commercial implications. If "demonstrate" is intended to mean executed contracts, compliance for distant future years of the control period becomes impracticable. If it refers only to planning and projections, this should be expressly clarified in the Regulations.

Inconsistent Compliance Obligations Based on Control Period Length: The current framework results in inconsistent obligations depending solely on the remaining duration of the tariff control period. Consider the following cases.

- Case 1: Where only one year remains in a control period, the licensee is required to demonstrate firm resource tie-up for that year, and only an indicative plan for subsequent years.
- Case 2: Where four years remain in a control period, the licensee is effectively required to demonstrate contractual tie-up for all four years.

As a result, the same future year may be subject to different compliance requirements depending only on whether it falls within or outside a control period. Such variability undermines the principles of consistency and predictability that should govern regulatory frameworks.

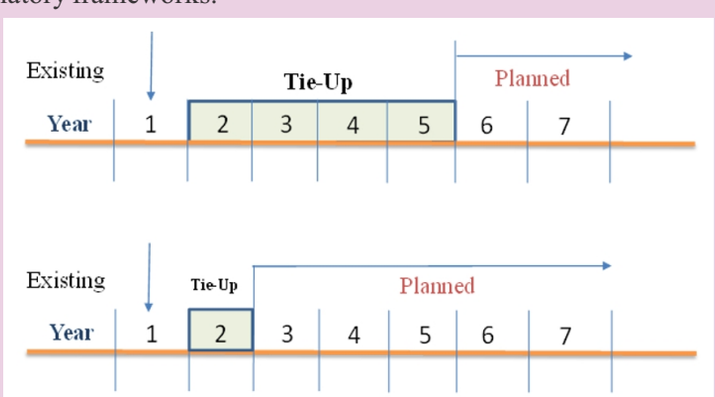


Figure 3. Demonstrate procurement arrangements

- **Uncertainty in Short-term Power Procurement:** Proposed Clause 11.3 states *"Based on the share in national peak provided in LT-NRAP, distribution licensee shall plan to contract the capacities (peak contribution * (1+National level PRM)) to meet their Resource Adequacy Requirement (RAR) at the time of national peak. The distribution licensee shall demonstrate to the Commission **100% tie-up for the first year and a minimum 90% tie-up for the second year to meet the requirement of their contribution towards meeting national peak**. Only resources with long / medium / **short-term contracts** shall be considered to contribute to the RAR"* and Proposed Clause 11.5 states *"Provided that, the Distribution licensee shall demonstrate to the Commission, the resource mix to meet 100% of the requirement of peak demand and energy requirement for the **entire control period** for which application for determination of retail supply tariff shall be made before the Commission, subject to other constraints in meeting the peak demand and energy requirement." (emphasis added)*

  The obligation requiring the Distribution Licensee to demonstrate a resource mix sufficient to meet 100% of peak demand and energy requirement for the entire control period can't be demonstrated if this portfolio of contracts would include short-term contracts. If the distribution licensee is to demonstrate this capacity by entering into firm contracts for delivery during the entire control period, it cannot include short-term contracts for the control period horizon beyond two years (Figure 4).

  This distinction is critical because, in practice, long- and medium-term contracts can be demonstrated with reasonable certainty at the time of tariff determination, whereas short-term procurement, by contrast, is inherently contingent on market conditions. Short-term power, asdefined in the regulation (less than one year), is typically executed closer to the delivery period and is influenced by prevailing demand-supply conditions, market prices, system constraints, and availability. Therefore, requiring the Distribution Licensee to demonstrate full short-term commitments, at the time of filing, for future control-period years is not contractually feasible unless it choses long-term and medium-term contracts this limiting optimization of its power procurement portfolio.

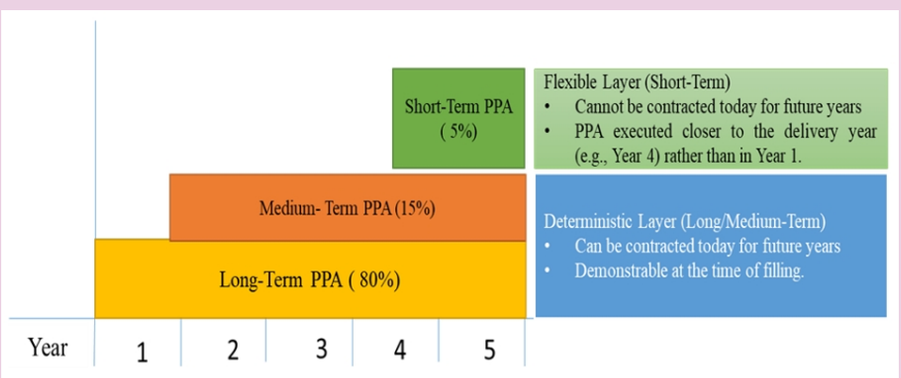


Figure 4. Power Procurement Timeline for Long/Medium/Short-term

- **Regulatory Framework for Spinning Reserve Deployment:** In Clause 9.3 (g), *"Operating (Spinning) Reserve constraints: Operating reserve constraints ensure that sufficient resources are in the system and kept online or on standby each hour to account for load forecast errors, intermittency of renewables or meeting contingencies in the real time. The thumb rule for operating reserve requirement shall be defined based on discussions with the state SLDC and shall be considered as an input parameter to the model or as specified in the national electricity policy, whichever is minimum. The SLDC from time to time shall specify the operating reserve requirement."*

  The CEA methodology assumes that spinning reserve requirements across states are coincidental. Spinning reserves are generally non-coincidental in nature since probability of simultaneous contingencies across all states is expected to be low. A, say, 5% spinning reserve requirement mandated for each state/DISCOM would result in more than 5% spinning reserve available at the national level.

  Availability of spinning reserve at the state-level is useful only if there is a suitable mechanism to 'deploy' and compensate for such spinning reserve. The SLDC may deploy the spinning reserve through a mechanism for ancillary service that would be called upon in a merit order and following application technical constraints, Thus,

the spinning reserve for inter-state capacity would be deployed and would be 'paid for' by the state beneficiary.

Spinning reserve at the inter-state level can be 'deployed' as the primary, secondary and tertiary response. This also requires that the generators operate under Automatic Generation Control(AGC). An amendment should be made to the Kerala Grid Code, 2005 to mandate AGC for all intra-state generators including captive generators above certain capacity. **In the absence of AGC for intra-state generators and a mechanism for deployment of reserve and compliance thereof, keeping aside available capacity for spinning reserve would only raise the cost of power procurement for the final consumers.**

IEGC Regulations, 2023 provides estimate of reserves to be procured by the respective state. In case of failure of the DISCOMs to procure such reserves, the NLDC is to procure the reserves and bill it to the respective state. It is suggested that spinning reserve obligations should be introduced in conjunction with a well-defined regulatory mechanism for their deployment and commercial settlement thereof. Furthermore, the cost of such reserves should be allocated to captive consumers thus bringing about a fair distribution of the obligation by the system constituents.

The term “thumb rule” should avoided in regulatory parlance as it lacks formal description. The word “state” in “state SLDC” is redundant and should be dropped

- **Capacity Credit for Conventional Sources: The draft regulation entails a resource adequacy planning exercise based on capacity credits outlined in the CEA's guidelines.** The approach for estimating capacity credit seems to bank on averages availability across the entire year, which understates the dependable contribution of generating stations during peak demand season. In practice, higher availability and therefore higher effective capacity credit is expected during peak season, as generators typically avoid scheduling maintenance during high-demand months. Coal-based thermal plants continue to serve as primary baseload resources and contribute significantly to peak demand requirements. After adjusting for auxiliary consumption, their net available capacity during peak periods remains relatively high. The graphical analysis (Figure 4&5) of 2025–26 for planned maintenance data for coal and lignite-based thermal plants in the Northern and the Southern Regions clearly indicates seasonally optimized planned outage pattern.

The total inter- and intra-state generating capacity for coal- and lignite-based in the northern region was 54.8 GW[7] at the beginning of 2025-26 (CEA, LGBR Report) (Figure 5). Taking normative availability of 85% that entitles the generators to recover full capacity charges, the average normative available capacity would be 46.58 GW. Based on the planned outages across thermal generating stations, we estimate the available capacity across the northern region on fortnightly basis, enabling a more granular evaluation of seasonal outage distribution.

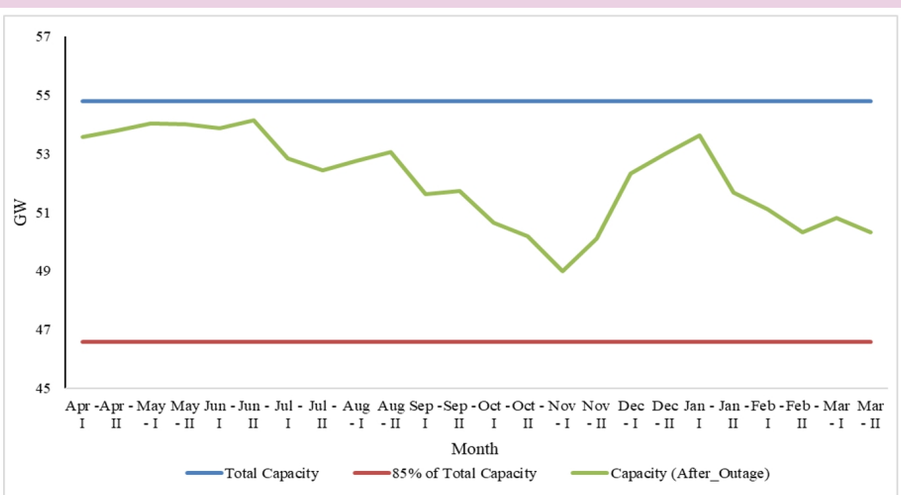


Figure 5. Seasonal Maintenance Impact on Northern Region Thermal capacity (2025-26)

[7]Capacity monitored by CEA.

Similar evaluation of the available capacity after accounting for planned outages for the Southern region is depicted in Figure 6. One can clearly note that the available capacity is more than 95% during the peak demand months of May-July in the Northern region, and it is above 90% throughout the year (Figure 5). Similarly, that the available capacity is nearly 100% during the peak demand experienced during the winter months in the Southern region, and it is above 85% throughout the year

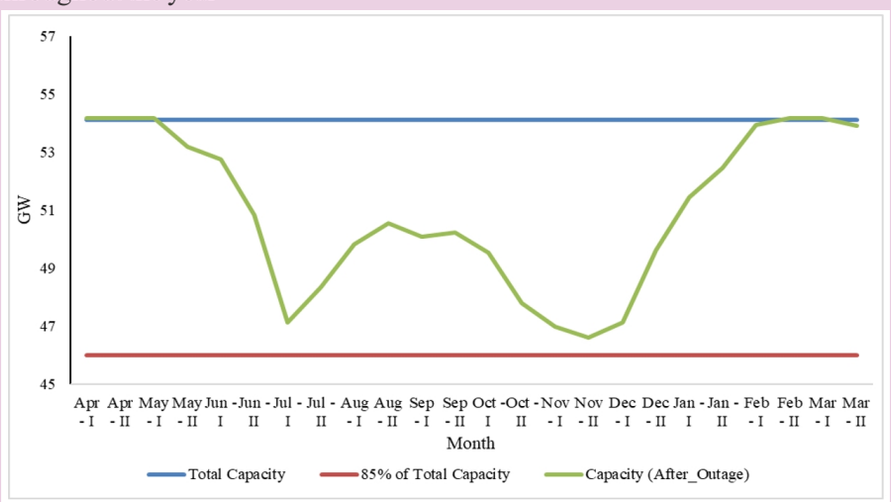


Figure 6. Seasonal Maintenance Impact on South-Region Thermal capacity (2025-26)[7]

The above analysis clearly highlights that reasonable capacity credit should be considered for coal based generating capacity, otherwise it would lead to over-estimation of the capacity shortage under the RA exercise, leading to tying up of excess capacity and thus placing undue burden of capacity charges on the DISCOMs. Accordingly, a minimum capacity credit in the range of 0.85 for coal-based plants should be adopted.

Similar state-specific analysis should be carried out across technologies for which a state has tied up capacity through PPAs. Capacity credit determination should account for state-specific characteristics, including demand seasonality, maintenance scheduling practices, and historical outage performance. Gas-based plants, where firm fuel supply is available, are dispatchable and capable of supporting peak demand, and may warrant higher capacity credit treatment. Hydro generation exhibits inter-annual and seasonal variability; run-of-river projects are particularly sensitive to flow conditions, while storage-based hydro offers greater flexibility. In states where peak demand coincides with monsoon months, hydro capacity credit may be assessed dynamically based on historical seasonal performance, although hydrological uncertainty remains inherent. Biomass plants may require seasonal capacity credit estimation due to fuel availability constraints. Capacity credit to biomass plants should be assessed based on seasonality of biomass availability and its storage, and its availability particularly during the national/state-level peak demand period. Overall, a more granular and state-specific approach would ensure realistic and economical RA assessment.

Optimal maintenance scheduling for Conventional Generation: Proposed Clause 9.3 (d) states **"***Unlike solar and wind, thermal resources are dispatchable. However, the thermal resources are bound by constraints such as maximum and minimum generation limits, ramp rates, spinning reserve offers**, plant availability** and unit commitment decisions. The dispatch (energy offer) plus the reserve offer (if, specified through regulations) for each generator is constrained to be within the maximum and minimum generation limits. Generation between two consecutive time blocks also must be within the ramping capabilities of the resources. Unit commitment decisions, such as start-up/shut-down, minimum up and down times, etc., require binary variables to implement and are to be included. Additionally, generation units may **have periods of outages** which may need to be captured by using an **availability factor**. The capacity for each year needs to be tracked by a constraint which shall ensure that the capacity in a particular year is equal to the capacity last year plus any new capacity investment minus capacity*

[7]Source: CEA LGBR 2025-26, Planned Maintenance Schedule

retirement, if any."

To ensure that the capacity tied up by the state adopts optimal maintenance schedule, guidelines for the same be issued by the Commission or be coded under the respective grid code. A specific framework for optimal maintenance scheduling may be included in the RA framework. This provision should ensure that planned outages of generating units are arranged in a coordinated manner so that excessive capacity is not scheduled for outage during peak demand periods. This should also ensure that necessary preventive maintenance is undertaken during low demand months. **A provision for optimal maintenance schedule of generating units may also be explicitly included under Clause 9.3**

- **Consumer Category-wise Demand Assessment and Forecasting:** The *proposed draft provision under Clause 6.3 to 6.6 and Clauses 6.11, address provision to load Forecast. Clause*

  *6.3 and 6.4 state that "6.3- The **distribution licensee** shall determine the load forecast **for each consumer category** for which the Commission has determined separate retail tariff.*

  *6.4 The distribution licensee shall determine the **energy forecast** for a **consumer category** by **adopting any of the following methodologies and/or combination** thereof :- (a) Trend Analysis i.e., Year on Year/Compounded Annual Growth Rate (CAGR) for past period and time series analysis; (b) End Use or Partial End Use method; (c) Auto-Regressive Integrated Moving Average (ARIMA); (d) AI including machine learning, ANN techniques; and (e) Econometric Modelling (specifying the parameters used, algorithm, and source of data)".*

  The draft Regulations assign significant importance to forecasting demand at the consumer-category level. However, its direct relevance to RA evaluation and procurement planning has not been clearly justified.

  Forecasting demand by consumer segment is generally more aligned with distribution system planning. It becomes particularly relevant in cases involving feeder segregation, targeted infrastructure upgrades, or category-specific load management strategies.

  In contrast, RA assessment and bulk power procurement decisions are typically based on aggregate system demand—both peak demand and energy requirements. Most RA modelling tools operate at the system level and rely on overall load projections, capacity contributions, reserve margins, and availability assumptions. Disaggregated consumer-level forecasts are not standard inputs in these models and usually do not materially alter adequacy outcomes.

  From a practical perspective, energy projections (in MWh) by consumer segment are often more reliable than attempting to forecast category-wise peak demand. Energy trends can be derived from historical billing data and provide a more stable basis for long-term planning analysis.

  Requiring detailed consumer-category forecasting as a mandatory component of RA planning would add procedural burden without delivering proportionate analytical benefits. It would be more appropriate to restrict such detailed forecasting requirements to contexts where they are clearly necessary, such as distribution network development, rather than applying them uniformly to RA assessments.

- **Probabilistic vs Scenario Forecasting Approach:** Proposed Clause 6.5 states *"The distribution licensee may use Electric Power Survey (EPS) projections as base and/or any other methodologies other than the above-mentioned after recording the merits of the method. Further, distribution licensee should use best fit of various methodologies for the purpose of demand/load forecast taking into consideration **probabilistic modelling** approach **for various scenarios (viz. most probable, pessimistic and optimistic)** as outlined under Regulation 6.4."*

  While draft regulation refers to probabilistic modeling; it should be noted, in practice this is frequently interpreted as the preparation of three demand projections - most likely, optimistic, and pessimistic. Although scenario analysis is a useful planning technique, it should not beconflated with full probabilistic modeling. A genuine probabilistic framework is inherently time-intensive, data-heavy and computationally demanding. It requires a structured treatment of uncertainty, including explicit probability distributional assumptions, risk metrics, and inter-variable relationships. Merely presenting three alternative cases, without a formal probabilistic structure, does not in itself,

meet this standard.

More importantly, it remains unclear how probabilistic outputs-typically expressed as confidence intervals or probability statements (e.g., a 90% likelihood of a certain demand level) are to be translated into concrete procurement or contracting decisions by distribution licensees. In absence of clearly defined decision protocols, such outputs may have limited practical utility. Currently, a scenario-based approach may meet planning requirements of a distribution licensee. It will be useful to clarify if the regulation proposes three scenarios-based analysis or whether the methodology itself has to be probabilistic, which is rather complex and time-demanding.

- **Rigid and Prescriptive Statistical Model Selection Criteria:** In draft Clause 6.6. it is mentioned that, *"For the purposes of deciding the load forecast for a customer category and the methodology to be used for load forecasting of a customer category, the* ***distribution licensee*** *must conduct statistical analysis and shall* ***select*** *the* ***method*** *for* ***which standard deviation is lowest and R-square is highest****."*

  Prescribing specific statistical or econometric performance indicators such as simultaneously minimizing standard deviation and maximizing R^2 may not be realistic in applied forecasting. For instance, a statistical (econometric) model may not simultaneously exhibit the highest R^2 and lowest standard deviation for the estimated variables in a consistent manner. Different model specifications often involve trade-offs between explanatory power, parsimony, and parameter stability. Therefore, prescribing rigid statistical performance criteria or mandating a particular methodological approach may not be appropriate.

  Variations in data availability, quality, and granularity especially with respect to consumer-level economic variables, tariff responsiveness, and socio-economic parameters make uniform methodological mandates impractical. The choice of forecasting methodology should remain flexible and context-specific, guided by data availability, quality, and the evolving structural characteristics of the sector. The regulation should not be very prescriptive in terms of methodological approach.

  Accordingly, the regulation may consider providing guiding principles rather than detailed and overly rigid methodological prescriptions, allowing distribution licensees to adopt appropriate approaches, that are consistent with available data, evolving system conditions, and operational feasibility.

- **Need to Provide Flexibility to DISCOMs on Selection of Demand Forecasting Methodology:** The regulatory framework should not confine utilities to rigid or narrowlyprescribed forecasting methods. Since forecasting accuracy directly influences capacity planning and investment decisions, flexibility in methodology is essential.

  Demand patterns are changing due to distributed energy resources, electric vehicles, evolving consumption behavior, and climate variability. At the same time, forecasting tools are advancing, including statistical learning, probabilistic modelling, and weather-adjusted techniques. Limiting utilities to predefined methods may restrict innovation and adaptability.

  The regulation should avoid limiting to only the currently adopted demand forecasting methodologies. Given that the accuracy of demand forecasting is a critical constraint in effective power planning and resource allocation, the regulation should provide room for hybrid and evolving methodologies. Additionally, periodic validation and refinement of forecasting models using real-time data and emerging trends in electricity consumption will help enhance reliability. Collaboration with research institutions, power utilities, and industry experts can further strengthen forecasting reliability and adaptability

- **Inclusion of Demand Response in Other Resource Capacity:** Demand response can provide necessary system support to meet peak demand that may be witnessed during limited number of hours in a year. As an alternate to tying up long- or medium-term capacity, a suitably designed demand response program offers an economically suitable option to optimize the RA plan of a DISCOM.

  It is recommended that "*Other Resource Capacity*", as referenced in Clause 10.7, explicitly include DR as a resource contributing to firm and flexible capacity, and accordingly be reframed as "*Other Resource Capacity*

and Demand Response". Demand Response can provide valuable flexibility by reducing peak demand or offering dispatchable load reduction, and its contribution should be appropriately reflected in the RAR calculations.

Additionally, the **methodology for assigning capacity credit to DR should be specified in Clause 10.3**, including how baseline consumption is established, verification and measurement protocols, expected availability during peak periods, and safeguards against double counting. Including DR in this manner would ensure a more comprehensive, transparent and reliability-aligned assessment of all resources contributing to system adequacy.

The distribution licensee should undertake a comprehensive evaluation to assess the potential and viability of demand response (DR) across its consumer base. This assessment should examine load flexibility, peak demand reduction potential, eligible consumer participation segments, and the overall economic and operational benefits of DR interventions.

Following this assessment, the **distribution licensee** may introduce structured DR programs, subject to the formulation and approval of appropriate regulatory provisions by the Commission. The regulatory framework should clearly define participation criteria, performance measurement protocols, incentive structures, and monitoring mechanisms to ensure transparent and effective implementation.

- **Long-Term Power Procurement and Minimum Duration :** Proposed Clause 4.1 (i) states that "*"Long-Term Power Procurement" or "Long-Term Contracts" means the procurement of electricity under any arrangement or agreement having a term or duration of seven years or more and up to twenty-five years, including arrangements or agreements that provide for an **extension** of **up to five years** at the option of the parties, or such other duration as may be specified from time to time under the Guidelines for Long-Term Procurement of Electricity issued by the Ministry of Power, Government of India". (emphasis added).*

  The definition of Long-Term Power Procurement applies to agreements with a tenure of seven years or more, including permissible extensions of up to five years as provided under the applicable guidelines. In view of this, the extension provision should be understood as operating within the framework of contracts that were classified as long-term at the time of execution.

  In case a distribution licensee entered into as short-term (up to one year) or medium-term (generally two to three years), and a later extension causes the total duration to cross seven years should not be regarded as long-term. The nature and category of such contract must be determined at inception, based on the applicable procurement framework.

  Clear tenure-based differentiation is necessary to preserve the integrity of procurement categories. Long-term contracts are intended to support structured investment decisions, appropriate risk allocation, and long-term system adequacy objectives. Short- and medium-term arrangements serve distinct purposes and should remain separately classified.

  Accordingly, **it is recommended that the Clause should explicitly clarify that the extension provision applies only to agreements originally executed as long-term contracts, and not to contracts procured under short-term or medium-term frameworks.**

- **Incorporating Optimality in Generation and Procurement Planning:** The expression **"optimum"** should be explicitly included in Clause 5.2 "*under both (b) Generation Resource Planning and (c) Procurement Planning,"*

  As the definition of RA already emphasizes an optimal generation mix, this principle should consistently guide the provisions relating to generation planning and procurement.

  The inclusion of the term "optimum" in these Clauses implies that decision-making should involve a structured comparative evaluation of alternatives, consideration of system constraints, renewable integration needs, storage requirements, and long-term cost impacts. Clarifying this intent within Clause 5.2 would ensure that optimality functions as a substantive planning criterion rather than a general descriptive expression.

- **Granularity of Historical Demand Data and Chronological Resolution of Planning Model:** Proposed Clauses 9.1 (b) and 9.2 states "*Actual demand met by the State / distribution licensee in granular time block resolutions*

*(**hourly**) for last 5 years."* and. *"The projected hourly orsub-hourly demand for the future years shall be used as inputs into the model. It shall be ensured that the generation expansion planning model chosen is capable of simulating on an hourly chronological resolution. This is necessary to capture the behaviour of the system with respect to ramping of conventional generation, profiles of RE generation, behaviour of energy storage, etc."*, respectively.

Proposed Clauses prescribe hourly granularity for historical demand data and require the generation expansion planning model to simulate on an hourly chronological basis.

Further, accurate RA and expansion planning require chronological simulation of system operations to capture intra-day variability, ramping constraints of conventional units, intermittency of renewable generation, and storage dispatch behaviour. While hourly resolution is a minimum analytical requirement, the increasing penetration of variable renewable energy and storage systems warrants consideration of finer temporal granularity, where feasible, i.e. without imposing unrealistic modelling requirements.

Prescribing only hourly granularity may not reflect prevailing operational data practices, where 15-minute block data is commonly maintained for scheduling and settlement. To avoid ambiguity, the Clause should mention 15-minute resolution data. Hourly data points can be derived from the 15-min block-wise data, if required.

It is recommended to rephrase the proposed Clause 9.1 (b), as follows:

"*Actual demand met by the State / distribution licensee in granular time block resolutions (**15-minute),** at least for the last 5 years."*

Similarly, Clause 9.2 may be rephrased as follows:

*"The projected hourly or sub-hourly demand for the future years shall be used as inputs into the model. It shall be ensured that the generation expansion planning model chosen is **at-least** capable of simulating on an hourly **(preferably 15-min block)** chronological resolution. This is necessary to capture the behaviour of the system with respect to ramping of conventional generation, profiles of RE generation, behaviour of energy storage, etc."*

- **Location-Specific Assessment of Renewable Energy (RE) Capacities and generation profile:** Proposed Clause 9.1 (g) states "*Capacities and generation profile of renewable generation."*

  Capacities & generation profile of RE resources, including contracted RE capacity, shall be evaluated in accordance with the resource characteristics of their respective locations. The assessment should account for site-specific factors such as solar intensity, wind regime, hydrological conditions, seasonal variations, and relevant contractual provisions, ensuring an accurate and location-sensitive representation for planning and RA assessment.

  Thus, it is recommended to rephrase the proposed Clause 9.1 (g) as follows:"*Capacities and generation profile of renewable generation **/ RE contracts as per the resources in the respective location.***"

- **RPO Constraints:** The draft Clause 9.3 (e) states: *"RPO constraints: Fulfilment of Renewable purchase obligation should be considered as one of the objectives of Resource Adequacy. Technology options like renewable generation for round the clock energy supply backed with storage (Battery and PSP), standalone renewable capacity along with hydro capacity for balancing renewable generation may be considered while carrying out resource adequacy exercise for distribution licensee."*

  The availability of RE available from non-obligated consumers, including behind-the-meter generation, should be duly considered while evaluating the DISCOM's Renewable Purchase Obligation (RPO). Distributed renewable sources such as rooftop solar systems, Renewable Energy Certificates (RECs), and renewable-linked standalone storage must be explicitly incorporated within the RPO accounting and compliance framework.

  Rooftop solar generation, whether consumed on-site or exported to the grid under net-metering arrangements, should be appropriately reflected in compliance calculations. Similarly, RECs acquired for meeting statutory targets must be transparently included. In cases where standalone storage is charged from renewable sources, its contribution should be recognized to ensure correct attribution of RE without duplication in RPO assessment.

- **Realistic Assessment of Firm Capacity:** Proposed Clause 10.2 states *"Each generator can provide a "firm capacity," which represents the amount of power the generator can reliably provide".*

  It is advisable to revise the wording to include contracts rather than generator as certain contractual agreements may not necessarily identify specific generating resources. Furthermore, this also excludes storage, or aggregator-based demand response contributions that can also provide 'firm capacity' in the context of RA.

- **Cost Assessment of Resource Adequacy Alternatives Scenarios:** Proposed Clause 11.4 (c) states "*The Distribution licensee shall submit all the assumptions relied by it in arriving at the optimal generation mix, including capital costs, variable costs, O & M costs etc. for each generation source/energy storage system. The Commission shall approve the Distribution licensee(s) contracting plan for coincident peak contribution and to meet their own energy and peak considering the fulfillment of conditions by the Distribution licensee(s) under these Regulations and subject to other terms and conditions of these Regulations by 31st December of each year for the period starting from the month of April in the subsequent year."*

  The analysis does not specify the cost implications associated with each RA alternative scenarios. While different procurement pathways are discussed, the corresponding financial implication for each option should also be specified along with their assumptions.For a comprehensive assessment, it is essential to quantify the cost of each RA scenario, including cost associated with capacity charges, energy costs, cost of maintaining reserve margins, and associated system integration expenses. This would enable an objective comparison of alternate power procurement portfolios.

  Further, when the, the analysis should clearly indicate the total system cost under each scenario for different levels of PRM. This would enable comparison of incremental costs and potential impacts across varying reserve margin assumptions.

  A structured cost–benefit comparison across scenarios (e.g., lower PRM vs. higher PRM) would provide greater transparency and support evidence-based decision-making. Presenting the marginal cost of reliability improvements would also help determine the optimal balance between adequacy and affordability.

- **Competitive and Technology-Neutral Power Procurement Framework:** In proposed Clause 14.11, it has been stated that: "*The distribution licensee must ensure that procurement process for the projected demand is undertaken and completed sufficiently in advance so that the procured capacity becomes available when it is required to serve the projected load. The following table gives the indicative number of years before which procurement process must be completed in advance as compared to the year of projected requirement for various types of generation and types of procurement:*

Resource	Long Term	Medium Term
Coal/Lignite based Capacity	7	2
Hydro	9	2
Solar	2	1
Wind	3	1
PSP	5	3
Other Storage	2	1
Nuclear	9	3

  A medium-term contract based on solar and wind energy are to be procured at least a year in advance. This essentially translates such contracts to short-term contracts. For consideration of medium-term contract, a duration of at least 2 years be earmarked.

  Pumped storage projects may further be categorized into two distinct groups: new greenfield pumped storage developments and existing hydro stations with storage augmentation. These two forms differ significantly in terms of capital requirements, construction timelines, and risk exposure, and therefore may warrant separate treatment within procurement planning.Renewable hybrid projects and renewable energy combined with storage systems

should also be separately recognized within the procurement framework. In addition, contracts such as Firm and Dispatchable Renewable Energy and Round-the-Clock supply and other such contracts may also be identified within the regulation.

The power procurement framework should be designed in a manner that promotes competition and avoids favoring any specific technology. Bid conditions need to remain broad and technology-neutral so that a wide range of developers can participate. When procurement structures are overly restrictive or tailored around particular sources, they may unintentionally limit competition and reduce the benefits of competitive price discovery. A more generic and inclusive structure would better support efficiency and transparency.

- **Clarity on the Use of "Equitable" in Procurement Criteria:** Proposed Clause 16.1 states *"Any new Capacity arrangement/tie-up shall be subject to the prior approval of the Commission in view of necessity, reasonableness of cost of power purchase and promotion of working in an efficient, economical and **equitable** manner."*

  In the present Clause, the use of the term "equitable" lacks sufficient clarity. This may have made there inadvertently as an 'equitable' power procurement would not fit the paradigm of competitive procurement.

- **Inclusion of Demand Response in Other Resource Capacity:** Demand response can provide necessary system support to meet peak demand that may be witnessed during limited number of hours in a year.
  Monitoring and Reporting: Proposed Clause 18.1 states *"The distribution licensee and SLDC shall abide by the timelines, procedure and methodology specified under these Regulations. The SLDC should monitor the entire process and shall submit **monthly compliance** to the Commission."*

  The Clause mandating submission of monthly reports especially in the context of LT resource adequacy requires further examination, particularly in terms of enforceability and regulatory value. It is necessary to clarify what specific instruments and procedural mechanisms are available to the Commission to act upon for such monthly submissions.

  For short-term power procurement, monthly reporting may be reasonable, as such transactions are dynamic and subject to market fluctuations. In that context, frequent monitoring can support transparency and timely oversight. However, for long-term planning instruments such as Long-Term NRAP and Long-Term DRAP, monthly reporting may not provide meaningful incremental value. Long-term adequacy projections, by their nature, do not typically undergo significant month-to-month structural changes.

- **Treatment for shortfall in RA Compliance and Capacity Tie-up:** Proposed Clause 18.2 states *"Distribution licensee shall comply with the RA requirement and in case of **non-compliance**, **appropriate non-compliance charge** shall be applicable for the **shortfall for RAcompliance**, which shall be determined on case-to-case basis."*

  The current framework does not explicitly distinguish between non-compliance due to timeline constraints and capacity tie-up shortages. Additionally, it is important to address how a capacity shortage can be assessed before reaching the defined compliance year.

  Furthermore, in scenarios where actual demand does not grow as projected, DISCOM that have maintained contracted capacities may require clarity on whether they would be incentivized for surplus capacity tie-up. Conversely, if DISCOM does not contract the required capacity due to lower-than-expected demand growth, it is essential to determine whether they would still be subject to the same penalties. Providing explicit regulatory guidance on these aspects will help ensure a balanced and fair approach to RA compliance, fostering both reliability and financial prudence in power procurement.

  Before any penalty or regulatory charge is imposed, the Distribution Licensee must be given a reasonable opportunity to explain the circumstances leading to the deviation. Non-compliance in RA or procurement may arise due to factors beyond the control of the licensee, including force majeure events, unforeseen demand variations, transmission constraints, or market disruptions. Therefore, a structured hearing or response mechanism should be embedded in the provision to ensure fairness and procedural transparency.

  Further, if the Commission determines that non-compliance has occurred and decides to impose a financial

charge or penalty, such amounts should not be recoverable through the Aggregate Revenue Requirement (ARR). Allowing recovery through ARR would effectively transfer the burden of non-compliance to consumers, thereby diluting accountability. Regulatory penalties are intended to incentivize compliance and discipline; their impact should remain with the entity responsible for the deviation.

It is suggested that the Commission may consider providing a clear definition of RA compliance in the draft RA Regulation Clause 18.2. Accordingly, the Clause should explicitly provide (i) an opportunity for the Distribution Licensee to present justification prior to determination of non-compliance, and (ii) a clear stipulation that any penalty or regulatory charge imposed shall not be passed through to consumers via tariff determination. This would ensure fairness, accountability, and protection of consumer interest.

- **Data Requirement and Sharing Protocol:** Proposed Clause 19.1 states " *The Distribution licensee shall maintain and share with STU/SLDC all data related to demand assessment and forecasting such as but not limited to consumer data, historical demand data, weather data, demographic and* ***econometric*** *variables, T&D losses, actual electrical energy requirement and availability including* ***curtailment****, peak electricity demand, and peak met along with changes in demand profile (e.g.: electric vehicles, cooling demand etc.), historical hourly load shape, etc*."A practical concern arises regarding the expectation that the Distribution Licensee should undertake econometric assessment using a wide range of economic variables. It is necessary to clarify what type of economic data a DISCOM is reasonably expected to access and analyze.

  In practice, a Distribution Licensee is primarily the custodian of operational and consumer-related data—such as connected load, category-wise consumption, billing records, demand patterns, loss levels, and collection efficiency. However, a full econometric model may require broader macroeconomic and socio-economic variables, including GDP growth, sectoral output, income levels, industrial production indices, demographic changes, urbanization trends, weather variables, and technological adoption indicators. These parameters are typically sourced from national statistical agencies, state departments, meteorological authorities, and other external institutions. The Distribution Licensee may not have direct or reliable access to all such datasets. In addition, many socio-economic variables are subject to definitional variations, periodic revisions, and methodological differences across data sources. If such parameters are imposed without clear standardization, it may lead to inconsistencies, unreliable modelling outputs, and avoidable disputes during regulatory scrutiny.

  Therefore, the regulatory framework should clearly delineate responsibilities. The DISCOM should primarily provide the data for which it is the natural custodian—namely, operational, demand, and consumer data. Any broader socio-economic inputs required for econometric modelling should either be specified with standardized data sources or be facilitated through designated nodal agencies. Excessive data-gathering burden on the Distribution Licensee, especially where such data lies outside its statutory control, should be minimized

- **Collection and use of data for Key Demand Drivers:** Proposed Clause 19.2 states *"The Distribution Licensee shall maintain comprehensive statistics and databases relating to policies and demand drivers, including but not limited to: household level indicators such as LED adoption, penetration of energy-efficient fans and appliances, and increased use of electricity for cooling, cooking; growth in commercial activities across geographic areas and regions; increase in the number of agricultural pumps and their solarization within the control area; changes in specific energy consumption and overall consumption patterns, including those of seasonal consumers such as tea plantations; implementation and impacts of Demand Side Management initiatives and Distributed Energy Resources; adoption of Electric Vehicles and Open Access; data centres; developments under the National Hydrogen Mission; and reduction in Aggregate Technical and Commercial (AT&C) losses."*

  At present, there is limited structured data available on key demand drivers such as LED adoption, penetration of energy-efficient fans and appliances, and the growing use of electricity for cooling and cooking. Without systematic collection of such information, it becomes difficult for a Distribution Licensee to accurately assess the underlying determinants of demand growth. Relying solely on aggregate historical consumption data does not provide sufficient insight into the structural evolution of consumer behavior or technology adoption trends.

  If the regulatory framework expects demand forecasting to incorporate appliance penetration, electrification

trends, and efficiency transitions, then the Commission may consider issuingspecific directions to initiate structured data collection at the consumer level. This could include periodic surveys, integration with energy efficiency programs, or coordination with state energy departments and utilities implementing electrification schemes. However, such requirements should be clearly defined and phased, as historical datasets for these variables are currently limited, and one-time data collection may not be adequate to derive statistically meaningful trends. **The distribution licensee may be asked to undertake data collection, regarding for**

e.g. appliance ownership including air conditioners, solar PV, storage/inverters and electric vehicles Historical block-wise supply curtailment data is also important to have a realistic assessment of energy requirement.

At the same time, consumer privacy and data protection must be carefully safeguarded. Any collection or analysis of household-level data should be anonymized and aggregated to avoid compromising personal information. The Commission may consider issuing separate guidelines outlining the relevant variables to be tracked and the protocols for data governance.

In this direction, smart meter data presents a significant opportunity. For consumers where smart meters have been deployed, high-resolution consumption data can provide insights into load patterns, peak contribution, seasonal variability, and potential demand response behavior. Properly anonymized analysis of such data can support improved demand forecasting, identification of demand response potential, and design of targeted programs for load shifting or peak reduction. **Leveraging smart meter analytics, while maintaining privacy safeguards, would provide a more reliable and dynamic basis for understanding evolving demand drivers compared to conventional historical aggregation alone**

- **Contracting of Optimal Resource Portfolio for Resource Adequacy Compliance:** Proposed Clause 14.5 states that *"The distribution licensee shall contract the optimal portfolio of resources to meet its future demand and Resource Adequacy Requirement (RAR) obligations, based on the output derived from the LT-NRAP study results. Long / medium / short-term firm contracts of **generation resources** shall be considered to contribute to the RAR. Power procurement through the **power exchanges**, such as the Day-Ahead Market segment**, shall not** be considered to contribute to RAR." (emphasis added)*

  For the purpose of RAR, generation resources shall include conventional generation, hydro, storage resources (including PSP and ESS), demand response, and contracted capacity through power traders, provided such arrangements are firm and are contractually backed.

  Short-term firm contracts may have a duration from a few time blocks to one year. Very short-term product like Day-Ahead Market (DAM) and Real-Time Market (RTM) segments, may be excluded however, other exchange traded products of relatively long-term tenure, for e.g. from a week to few months should also be allowed as a part of firm short-term contracts. Such procurement should be undertaken through transparent and competitive bidding processes. It should be noted that exchange-based transactions represent binding and financially firm commitments. Thus, their blanket exclusion from RAR may not be appropriate. Instead, eligibility may be linked to the firmness, tenure, and reliability of such procurement.

- **Inclusion of Demand Response in Other Resource Capacity:** Demand response can provide necessary system support to meet peak demand that may be witnessed during limited number of hours in a year. **Procuring beyond RA Plan***:* Proposed Clause 17.1 states that *"The distribution licensee **may procure additional power beyond the approved resource adequacy plan**, provided such procurement complies with the orders issued by the Commission." (emphasis added)*

  The Distribution Licensee shall adhere to the approved Resource Adequacy (RA) Plan as the primary framework for meeting its demand obligations. **Procurement of power beyond the approved RA Plan shall not be undertaken as a routine practice, as such additional procurement would dilute the purpose and discipline of resource adequacy planning.**

  However, there may be legitimate circumstance that warrant deviation from the approved RA Plan. In the case of

Long-term procurement, the distribution licensee shall submit an updated resource adequacy plan for approval and obtain appropriate amendment from the commission prior to undertaking such procurement.

For medium-term/short-term procurement, the distribution licensee rebalances its portfolio to optimize its overall power procurement strategy. Such rebalancing may include contracting additional power or offloading existing contracted capacity, as deemed necessary.

Any such rebalancing shall be permitted subjected to the condition that the distribution licensee submits an updated resource adequacy plan and demonstrates sound economical and commercial justification for the proposed changes.

Power Lexicon

Rajasthan Electricity Regulatory Commission (RERC) DF/DSM Regulations, 2026

The draft **Rajasthan Electricity Regulatory Commission (RERC) DF/DSM Regulations, 2026** establish a framework for integrating demand-side resources into power system planning. In response to rising demand variability and renewable integration, distribution licensees are required to actively manage consumer demand. Section 3.4 outlines the guiding principles for implementing and evaluating demand-side interventions, focusing on reliability, cost efficiency, and optimal grid utilization.

Demand Flexibility (DF): Demand Flexibility refers to the capability of consumer loads to adjust their electricity consumption patterns over time (such as hourly or other intervals). This adjustment helps make electricity more cost-effective for consumers while also reducing or postponing system-related expenses. It includes end-use loads that can either increase or decrease their consumption as part of demand response actions.

The figure below illustrates DF, where electricity consumption varies over time in response to price signals. The typical load profile (blue) is adjusted to a price-responsive load (green), which decreases during high-price periods and increases during low-price periods. This demonstrates the ability of demand-side loads to both increase and decrease consumption, making electricity more affordable for consumers while reducing peak demand and helping defer system costs.

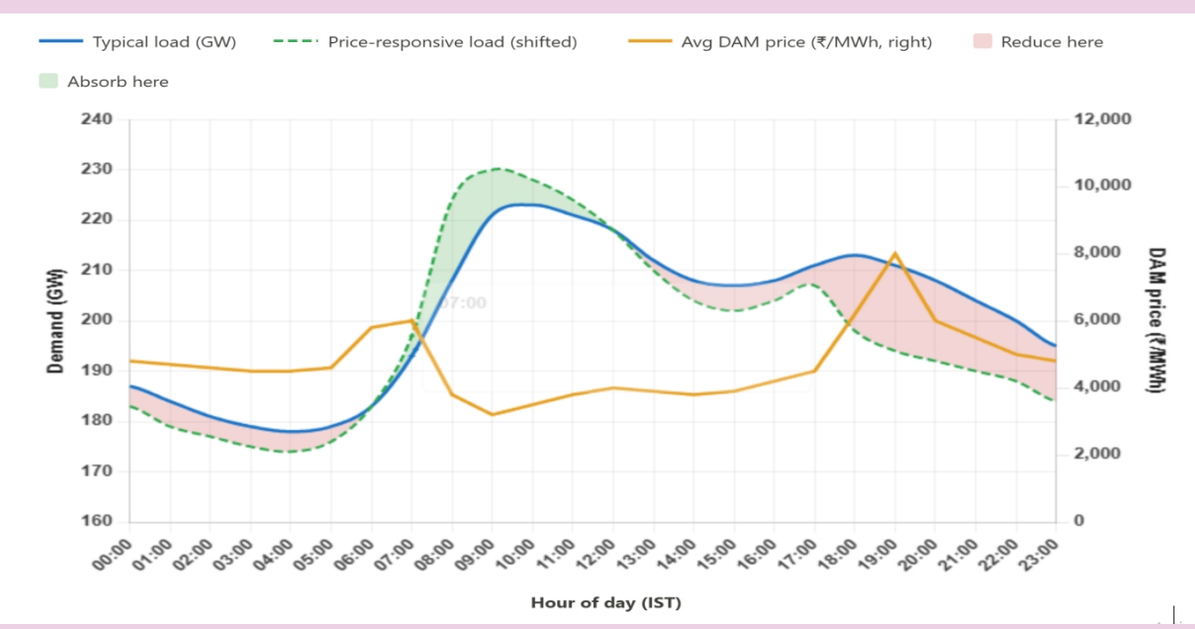


Figure 1: Demand Flexibility through Price-Responsive Load Adjustment

Demand Response (DR): Demand Response is the modification of electricity usage by end-users or within a control area, carried out either manually or automatically, individually or in aggregated form, in reaction to the needs of the power system.

Demand Side Management (DSM): Demand Side Management encompasses the strategies and initiatives undertaken by a Distribution Licensee to influence how electricity is consumed. This may involve increasing, decreasing, or shifting demand between peak and off-peak periods, with the objective of minimizing overall system costs.

The figure illustrates a typical DSM load curve where the original load (blue line) exhibits a pronounced evening peak between 18:00 and 23:30, reaching up to 227 GW. Through DSM intervention, this night-time peak is clipped at 210 GW (red shaded region), and the corresponding load is redistributed equally to the solar hours between 09:00 and 16:00 (amber shaded region), where renewable generation is abundantly available. This demonstrates load shifting from high-demand periods to lower-demand periods, helping to reduce peak load and overall system costs while maintaining the same total energy consumption.

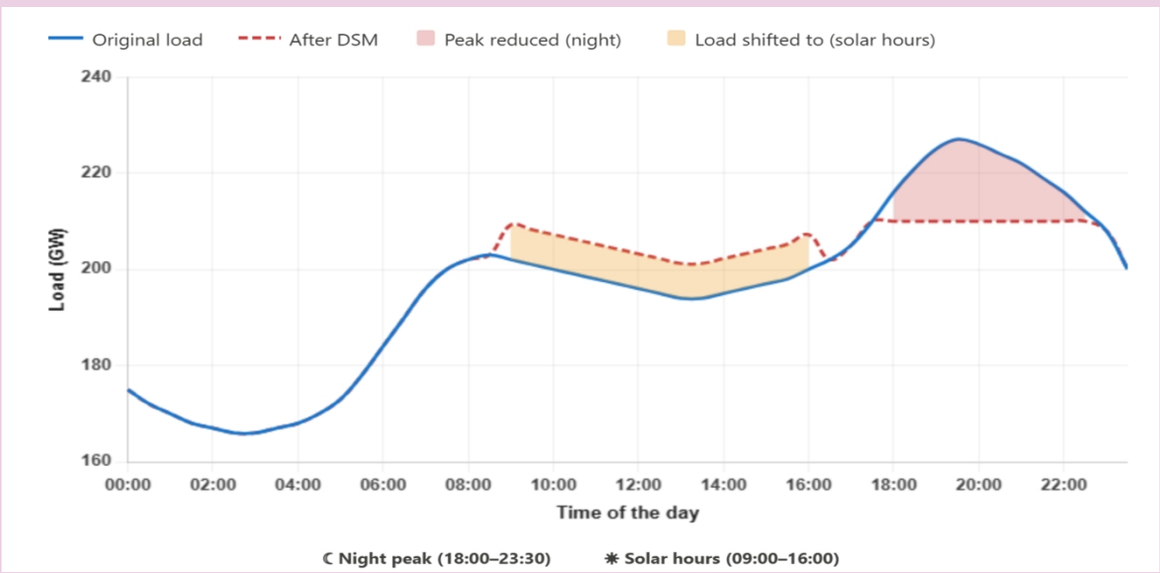


Figure 2: Effect of DSM on Electricity Demand Across the Day

Demand Flexibility Portfolio Obligation (DFPO)

Under the draft regulations issued by the RERC, the DFPO refers to the mandatory requirement for distribution licensees to maintain a specified level of flexible demand capacity on an annual basis. This enables consumers to shift or vary electricity usage in response to grid conditions, thereby improving grid reliability, reducing peak demand, and facilitating efficient integration of renewable energy in the state.

The DFDO targets are specified as a percentage of the previous year's peak demand:

Financial Year	DFPO as percentage of peak demand experienced in previous Financial Year
FY 2026–27	0.25%
FY 2027–28	1.0%
FY 2028–29	1.5%
FY 2029–30	2.0%

Rajasthan Electricity Regulatory Commission (Framework for Resource Adequacy) Regulations, 2026

These definitions are derived from the draft **Rajasthan Electricity Regulatory Commission (Framework for Resource Adequacy) Regulations, 2026,** which establishes a scientific, reliability-based framework for planning generation capacity to meet future electricity demand with adequate reserves and optimal mix.

Planning Reserve Margin (PRM)

Planning Reserve Margin means the percentage of capacity over and above the State's coincident share in national peak demand, as specified by the Central Electricity Authority or approved by the Commission from time to time. The PRM is determined based on reliability indices such as Loss of Load Probability (LOLP) and Normalized Energy Not Served (NENS), and is considered for generation resource planning.

PRM serves as a reliability margin to ensure sufficient capacity is available to handle uncertainties such as generator outages or higher-than-expected demand.

Table 1: Reliability Indices for Resource Adequacy

Parameter	Definition
LOLP	Probability that system demand exceeds available generation capacity within a year, indicating risk of supply shortage.
EENS	Total expected energy (in MUs) not supplied due to insufficient generation capacity over a year.
NENS	Ratio of EENS to total system energy, providing a normalized measure of energy shortfall.

Capacity Credit (CC)

Capacity Credit (CC) is the reliable contribution of a generation resource toward meeting demand, determined by the distribution licensee using a net load–based approach, where the contribution of the resource during system stress (top net load hours) is evaluated.

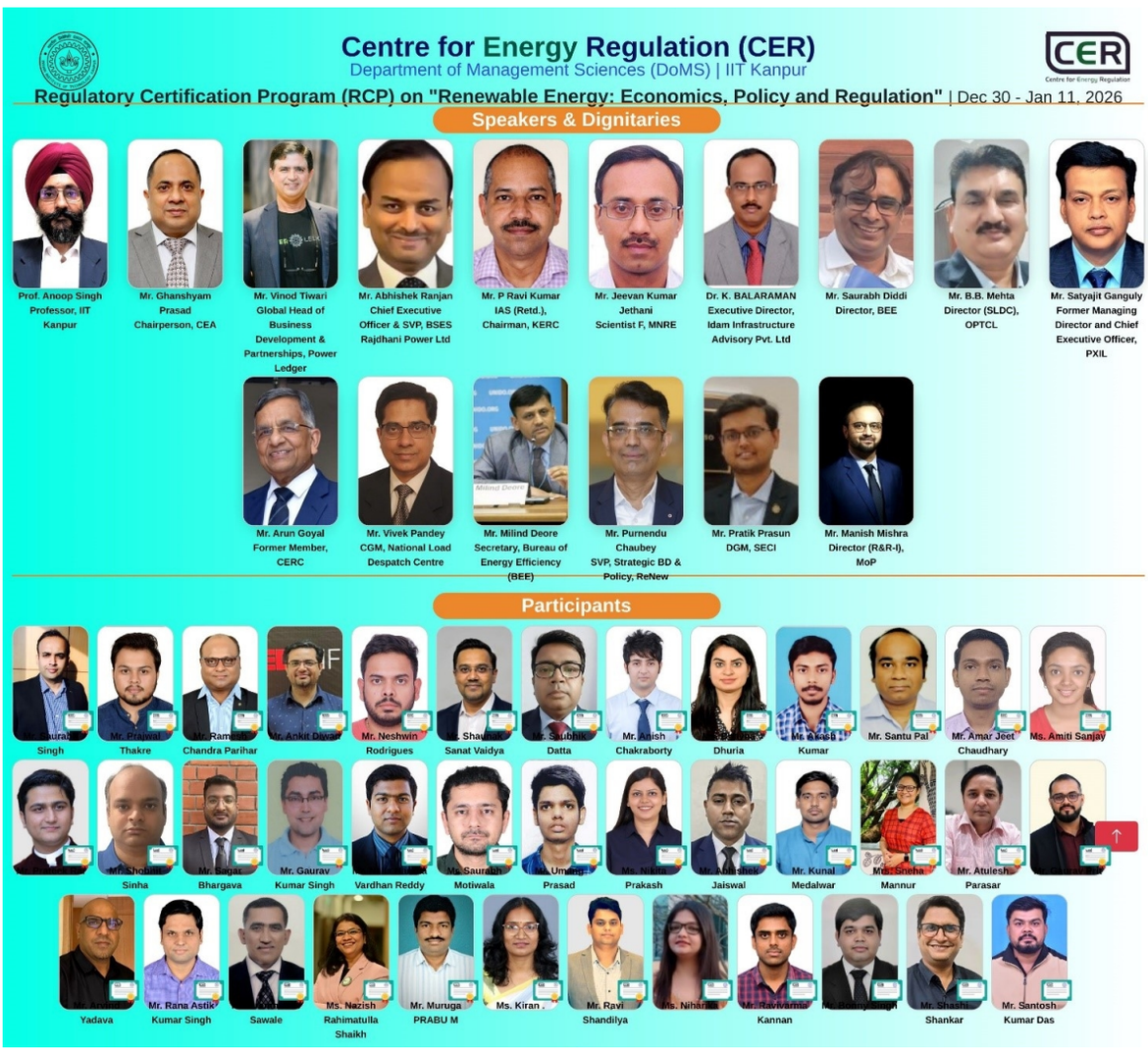
It is calculated by analyzing historical hourly load data, adjusting for renewable generation to obtain net load, and then measuring the generation available from the resource during the top load hours (typically top 250 hours). The final Capacity Credit factor is obtained as the ratio of generation to installed capacity during these critical hours, and the value used for planning is the rolling average of such CC values over the past five years.

$$\text{CC factor} = \frac{\text{Sum of RE Generation for top x hours}}{\text{Sum of RE Capacity for top x hour}}$$

Resource Adequacy Requirement (RAR)

Resource Adequacy Requirement (RAR) represents the total capacity that a Distribution Licensee must secure to meet projected demand along with the required reserve margin at the time of national peak. In the document, RAR is the final outcome of the resource adequacy planning process, derived after demand forecasting, adjustment of available capacity using Capacity Credit (CC), and inclusion of Planning Reserve Margin (PRM). The regulations mandate that licensees must ensure 100% capacity tie-up for the first year and at least 90% for the second year to meet RAR. Additionally, the procurement mix is specified, with 75–80% through long-term contracts, 10–20% through medium-term contracts, and the remaining through short-term contracts. Importantly, only contracted capacity is considered for meeting RAR, while market-based purchases such as Day-Ahead Market (DAM) or Real-Time Market (RTM) are excluded.

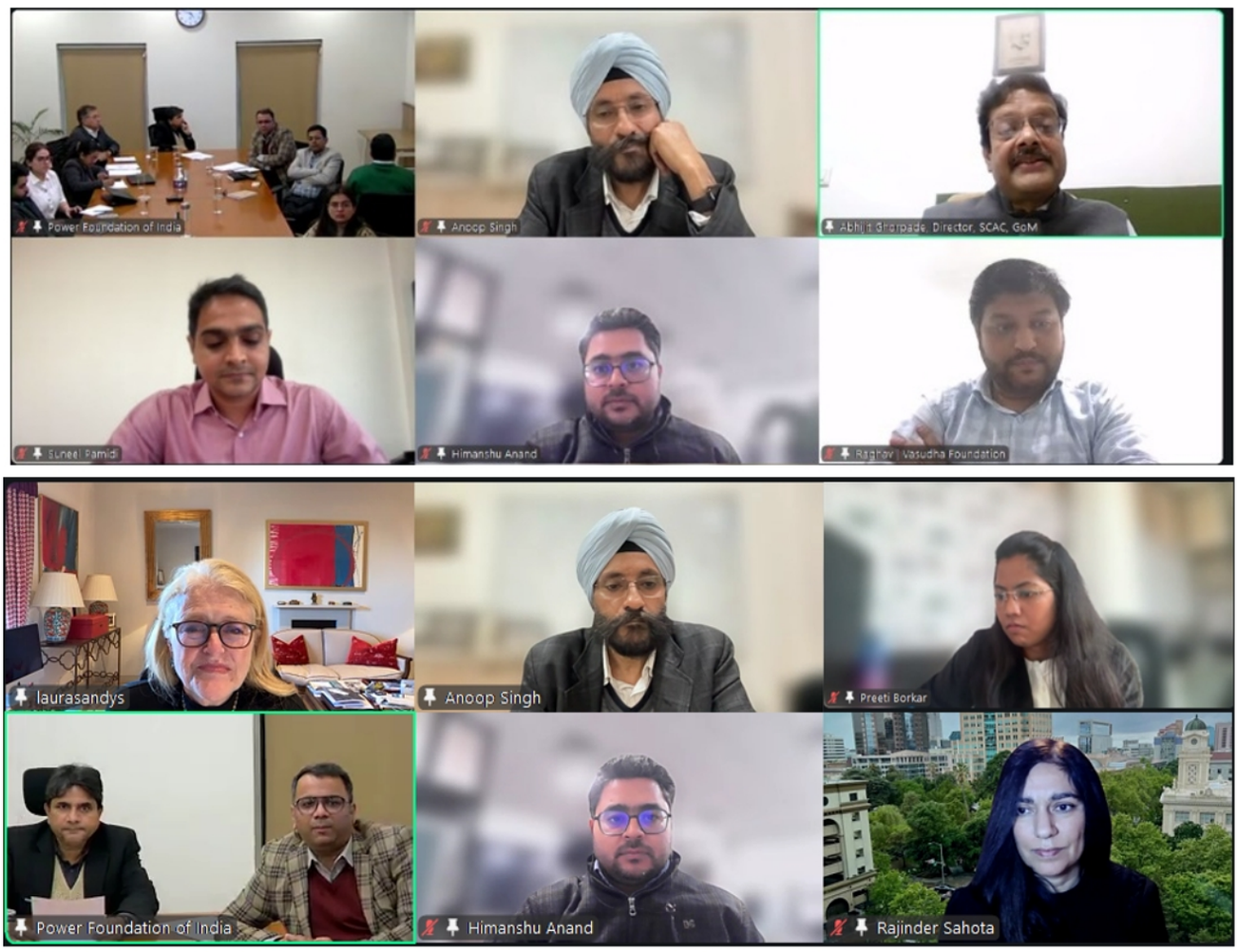
3rd Regulatory Certification Program (RCP) on "Renewable Energy: Economics, Policy and Regulation"



The Centre for Energy Regulation (CER), in collaboration with the Energy Analytics Lab (EAL), conducted the Regulatory Certification Program (RCP) on *"Renewable Energy: Economics, Policy and Regulation"* to provide a detailed perspective on the economic foundations for a better understanding of the evolving regulatory and policy framework for renewable energy. The online sessions for the program were scheduled from 13th December, 2025 to 11th January, 2026.

Key speakers for the program included Mr. Ghanshyam Prasad (Chairperson, CEA), Mr. Arun Goyal (Former Member, CERC), Mr. Milind Deore (Secretary, BEE), Mr. Manu Srivastava (Additional Chief Secretary, Department of New & Renewable Energy, Government of Madhya Pradesh), Mr. Manish Mishra (Director (R&R-I), Ministry of Power), Mr. Saurabh Diddi (Director, BEE), Mr. Jeevan Kumar Jethani (Scientist F, MNRE), Mr. Balaraman Kannan (Former Director General, NIWE, MNRE), Mr. Satyajit Ganguly (Former Managing Director & CEO, PXIL), Mr. Abhishek Ranjan (CEO, BSES Rajdhani), Mr. Vivek Pandey (CGM, NLDC), Mr. B. B. Mehta (Director (SLDC), OPTCL), Mr. Prateek Prasun (DSM, SECI), Mr. Purnendu Chaubey (Senior Vice President – Strategic Business Development & Policy Advocacy, ReNew), Mr. Vinod Tiwari (Global Head of Business Development & Partnership, Power Ledger), and Prof. Anoop Singh (Founder & Coordinator, CER & EAL, IIT Kanpur). Mr. P. Ravi Kumar, IAS (Retd.), Chairman, KERC, graced the valedictory function as the Chief Guest and presented certificates to the participants.

High-level Stakeholder Consultation on "Policy, Regulatory, and Institutional Framework for Net Zero: International, National and Sub-national Experiences"



The Centre for Energy Regulation (CER), IIT Kanpur, with support from the Power Foundation of India (PFI), successfully convened an online High-level Stakeholder Consultation on *"Policy, Regulatory, and Institutional Framework for Net Zero: International, National and Sub-national Experiences"* on 4th February, 2026. The workshop brought together leading experts, policymakers, and practitioners to deliberate on institutional pathways for the net-zero transition, drawing on Indian subnational experiences and lessons from international experience, such as the UK and California. The programme began with opening remarks by Mr. Anshuman Srivastava (Executive Director, PFI), followed by a thematic address by Prof. Anoop Singh, who outlined the evolving net-zero landscape and moderated the workshop proceedings. The first session, centred on sub-national pathways, featured perspectives from Mr. Abhijit Ghorpade (Director, State Climate Action Cell, Government of Maharashtra), Mr. Suneel Pamidi (Director, Directorate of Environment and Climate Change, Government of Kerala), and Mr. Raghav Pachouri (Associate Director, Vasudha Foundation), who reflected on emerging state-level approaches to climate governance. The second session focused on international experience, with Ms. Laura Sandys (Chair of Green Climate, Chair of the UK Energy Digitalisation Taskforce, Chair of the Energy Networks Innovation Taskforce) and Ms. Rajinder Sahota (Deputy Executive Officer, Climate Programs and Research, California Air Resources Board) sharing insights from the UK and California respectively. The event concluded with closing remarks from Mr. Himanshu Chawla (Head (Regulatory), PFI), who highlighted the significance of such stakeholder engagements in shaping India's net-zero journey.

SAFIR Core Course on "Infrastructure Regulation: Markets, Green Energy Transition and Regulatory Governance"

The Centre for Energy Regulation (CER), IIT Kanpur, organized the SAFIR Core Course on “Infrastructure Regulation: Markets, Green Energy Transition and Regulatory Governance” from 6th to 9th February, 2026 at the IIT Kanpur Outreach Centre, Noida, supported by South Asia Forum for Infrastructure Regulation (SAFIR).

The program aimed to provide participants with insights into infrastructure regulation, evolving energy markets, regulatory governance, and challenges associated with the clean energy transition.This programme includes various stakeholders from countries such as Sri Lanka, Bangladesh, India, Bhutan, and Nepal, with backgrounds in power exchanges, regulatory commissions, legal domains, and related fields.The course brought together experts from regulatory bodies, government institutions, industry, and academia to share their perspectives and experiences.

The inaugural session was graced by Mr. Harpreet Singh Pruthi (Secretary, Central Electricity Regulatory Commission), as the Chief Guest. The program featured distinguished speakers including; Mr. Ghanshyam Prasad (Chairperson, Central Electricity Authority), Dr. Anil Kumar Jain (Chairperson, Petroleum and Natural Gas Regulatory Board), Dr. M. P. Tangirala (Member, Telecom Regulatory Authority of India), Mr. S. R. Narasimhan (Former CMD, Grid Controller of India Limited), Dr. Sushanta K. Chatterjee (Chief (Regulatory Affairs), Central Electricity Regulatory Commission), Mr. D. K. Srivastava (Chief Engineer, Ministry of Power), Mr. Sanjay Sen (Senior Advocate, Supreme Court of India), Dr. G. Raghuram (Former Director, IIM Bangalore) and Prof. Anoop Singh.

The valedictory function was graced by Mr. Jishnu Barua (Chairperson, Central Electricity Regulatory Commission), as the Chief Guest. The program also included site visits to Noida Power Company Limited (NPCL) and Grid Controller of India Limited (GRID-INDIA) to provide participants with practical exposure to power sector operations.

5th Global Regulatory Perspectives Programme (GRPP) for Commissioners of Electricity Regulatory Commissions


The Centre for Energy Regulation (CER), IIT Kanpur organized the 5th Global Regulatory Perspectives Programme (GRPP) from 11th to 13th February, 2026, in Lisbon, Portugal. Supported by the Forum of Regulators, the programme enabled Indian delegates to gain international exposure in Portugal through institutional visits, including Endesa, and regulatory exchanges with ERSE on market design, tariffs, governance, and emerging energy innovations.

The program featured distinguished speakers boards member from ERSE and other senior member from ERSE and EDP Labelec. The programme concluded with technical exposure visits, including a site visit to Tratolixo, an urban waste treatment facility, providing participants with insights into sustainable waste management and energy-related infrastructure. The programme was attended by Members of various State Electricity Regulatory Commissions across India, along with Prof. Anoop Singh. The valedictory function was graced by Ambassador Puneet R. Kundal, Ambassador of India to Portugal. In his remarks, he provided a concise historical perspective on the longstanding relationship between India and Portugal, highlighting its evolution and continued relevance in the contemporary context.

Regulatory Certification Program

REGISTRATION OPEN till 28th May, 2026

CER in association with EAL, is pleased to announce the **6th Regulatory Certification Program on "Power Sector Regulation: Theory and Practice"** commencing from **30th May to 21st June, 2026**. The program would be conducted under the aegis of Centre for Continuing Education, IIT Kanpur. For further program details including program duration, key topics, schedule, admission process and fee, please visit:

https://cer.iitk.ac.in/psr_reg/?id=1#register

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