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Power Chronicle

Power System Overview & Analysis

Power Market Overview & Analysis

Regulatory & Policy Perspective

EAL News

Editorial

The impact of variability of weather on electricity demand is highlighted by the experience of recent months. Rainfall variability not only impacted the pattern of demand for the agricultural sector, but this associated with temperature variations also affected demand for electricity for cooling purpose. The short-term power market continues to witness a resource crunch as price often hit the market cap set by the CERC. Higher market prices across market segments including DAM, RTM and G-DAM point towards a pattern characterized by lower prices coinciding with solar generation and higher prices during evening and late night. This clearly highlights the role of demand response and time of day pricing.

The market for Renewable Energy Certificates (RECs) continues to remain subdued with a single trading day over a month leaving it disconnected from the market dynamics. Price difference between the G-DAM and DAM market segments show a higher value of green attributes vis a vis the market discovered price of RECs. In general, solar hours witness lower market prices suggesting growing surplus availability of green power during those hours.

Resource adequacy is an essential part of utilities' planning to meet the expected luxury demand of its consumers over long, medium as well as short-term. The long-term electricity demand forecasting and power procurement planning, considering adequate reserve requirement, is central to resource adequacy in the sector. EAL's experience in undertaking such detailed studies for the states of Uttar Pradesh & Chhattisgarh, and forecasting for the states of Rajasthan & Gujarat highlights their role in ensuring cost effective decisions while ensuring reliability of supply for the consumers. The experience also highlights that the methodological approach, while remaining broadly similar, needs to be tailored to address the circumstances of the respective state. Availability of data, policy and realistic targets for energy efficiency, solar rooftop, solarisation of agriculture as well as the demand response program plays a vital role in the reliable & economic planning of the utilities.

The guidelines for resource adequacy issued by the CEA would emphasise broader synergy across the sector. Availability of reliable data, visibility of behind the meter generation and granularity of the forecast and resource planning should be the key priorities to implement nationwide plan to assess resource adequacy, which continues to emphasise greater reliance on the 'creation of capacity'. Greater role of demand response, and better grid visibility and forecast thereof can also help address resource requirements for the sector.

Anoop Singh
Founder & Coordinator, Energy Analytics Lab

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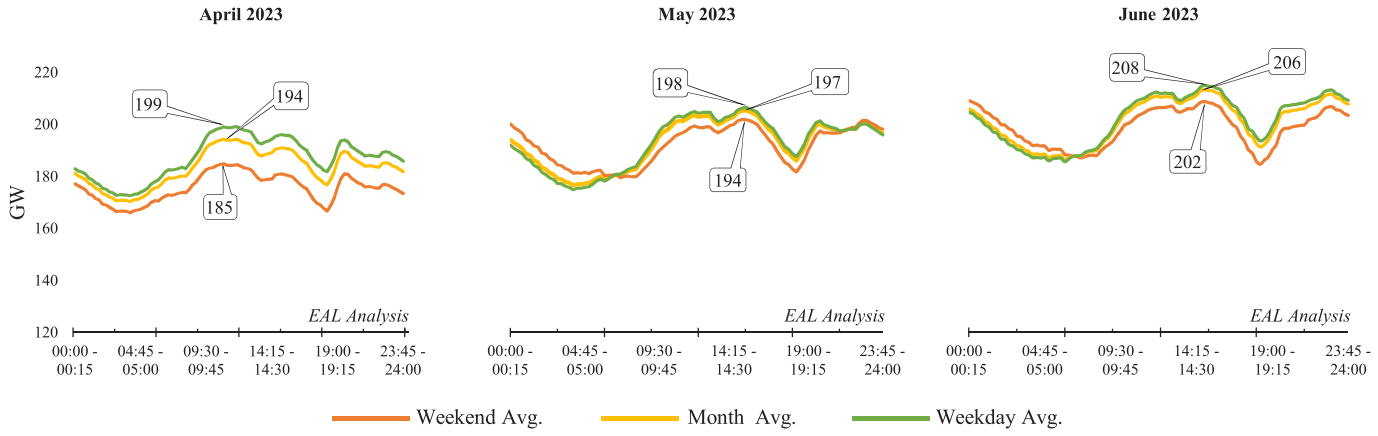
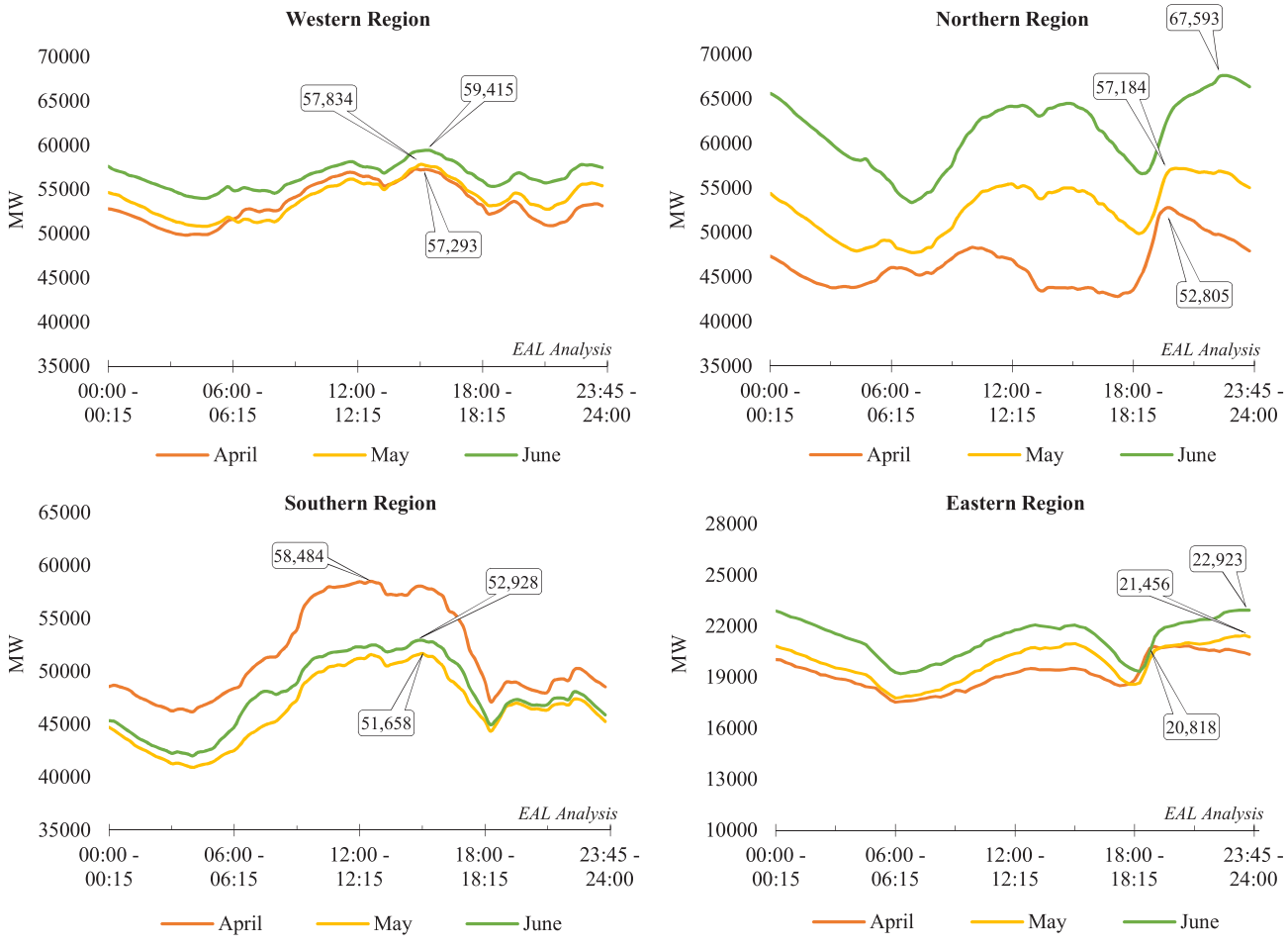
Power System Overview & Analysis

All India Demand Met Profile

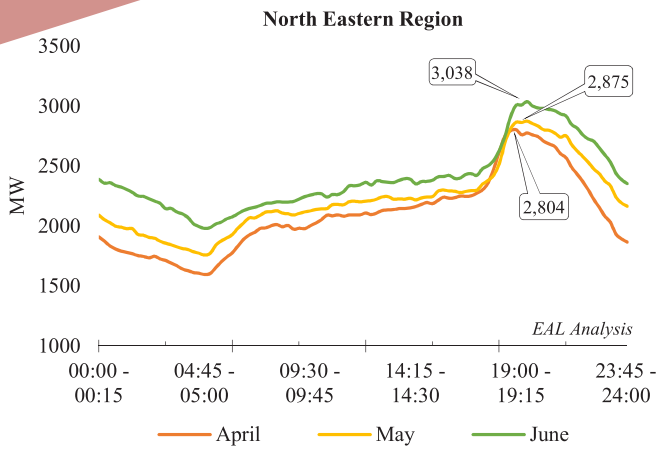


From April to June quarter, all India peak demand reached 223 GW (15:15 - 15:30) on 9th June 2023, about 5.7% higher than the previous year's peak demand recorded at 211 GW (15:00 - 15:15) on 9th June 2022, during the same quarter.

Region-wise Demand Met Profile



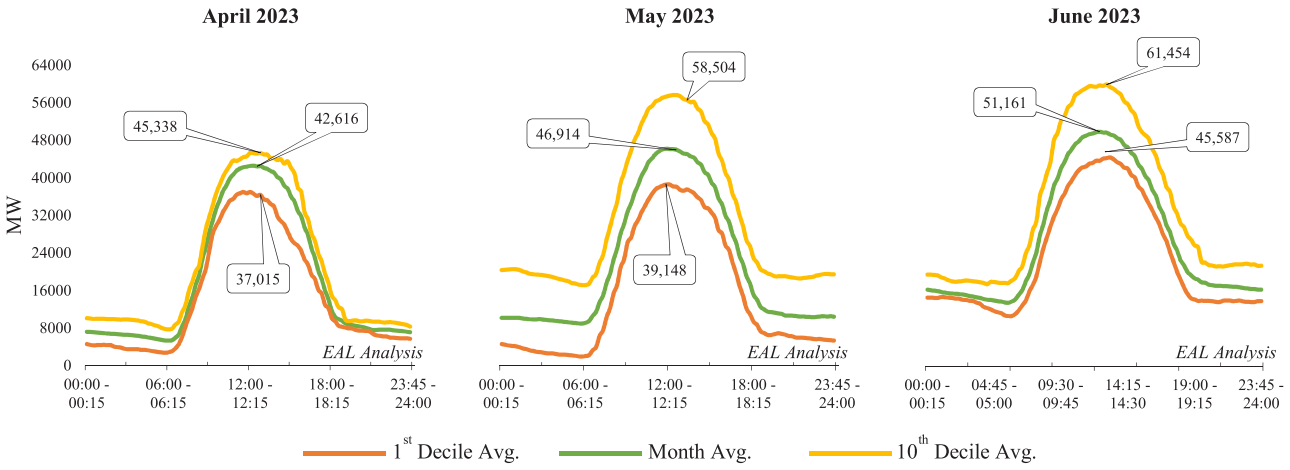
For more information Click here



- Average demand is found to be higher for Southern region as compared to the other regions in the month of April.
- Significant decrease in demand can be observed from 17:30 to 19:00 hrs for Southern and Eastern regions in all the three months.
- Significant increase in demand can be observed from 19:15 to 22:00 hrs & gradual decrease for North Eastern region in all the three months.

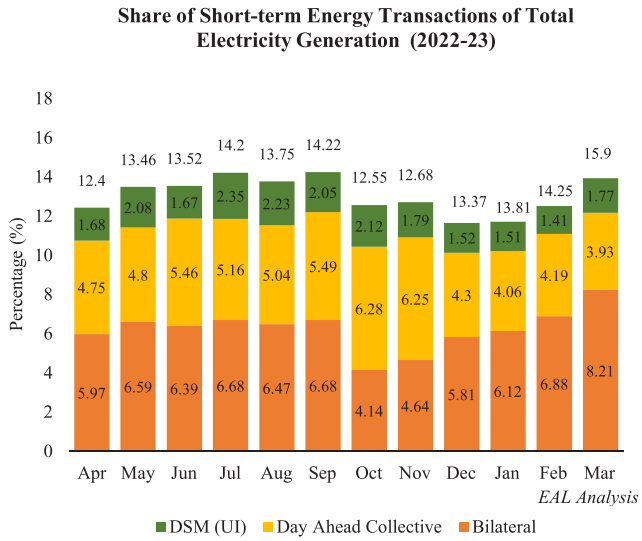
Demand and generation profiles at National, Regional and State-level can be accessed on EAL's web portal.

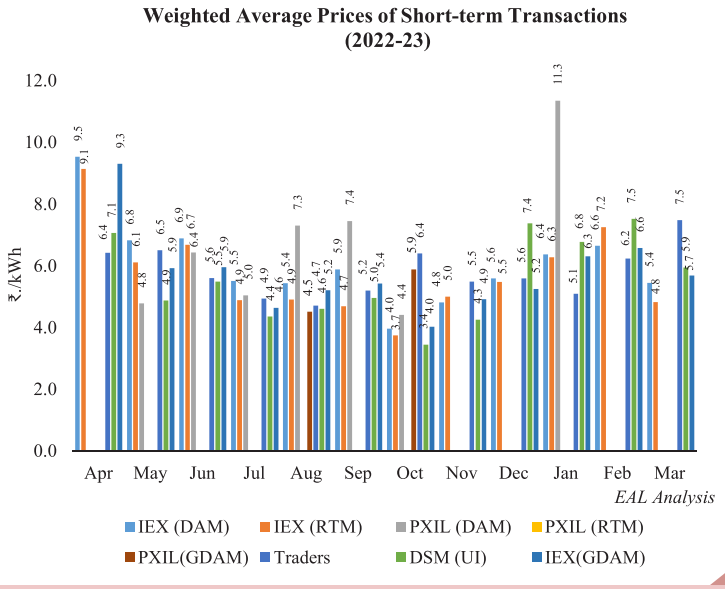
All India Renewable Energy (RE) Generation Profile



All India peak RE generation reached 64.87 GW (12:45 – 13:00) on 14th June 2023, about 20.98% higher than the previous year's peak of 53.62 GW (12:30 - 12:45) on 22nd May 2022.

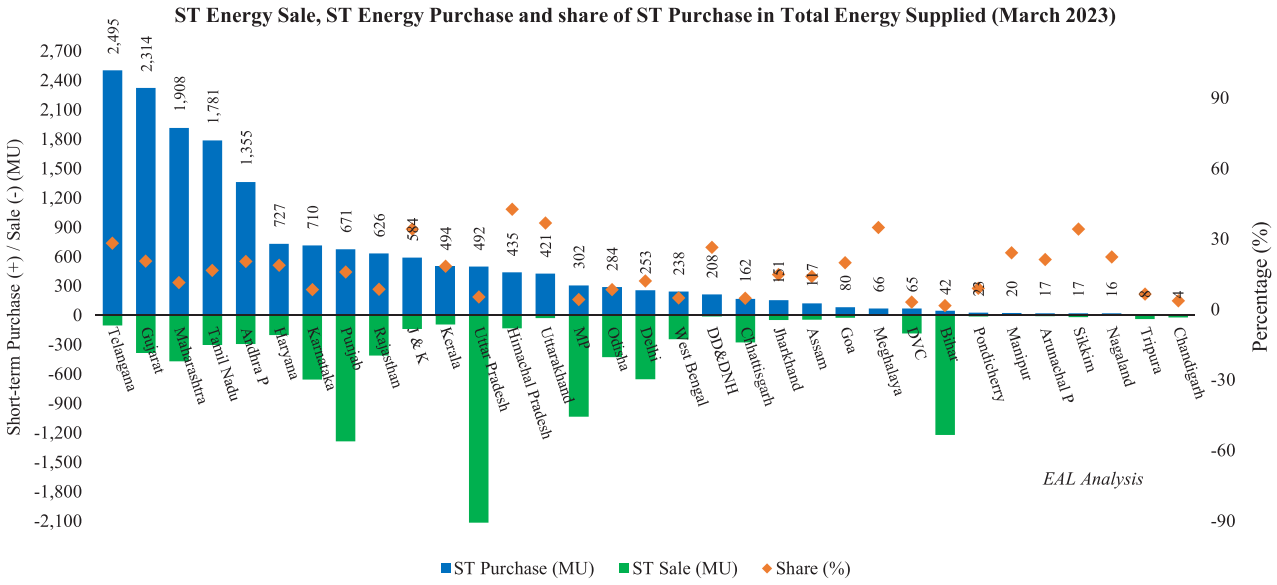
Short-term Energy Transactions





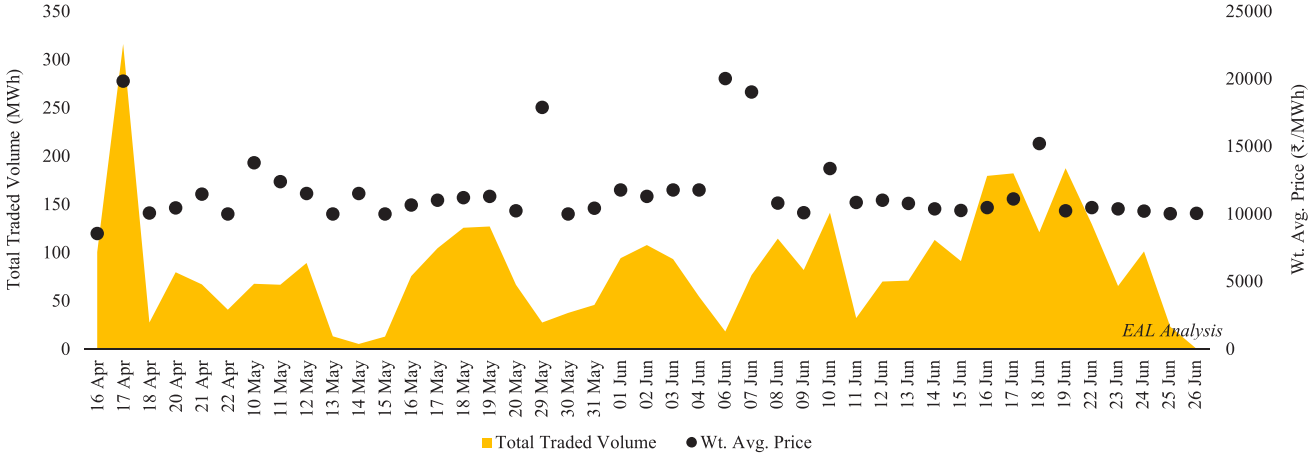
For more information Click here

Monthly Short-term (ST) Purchase and Sale Quantum across States

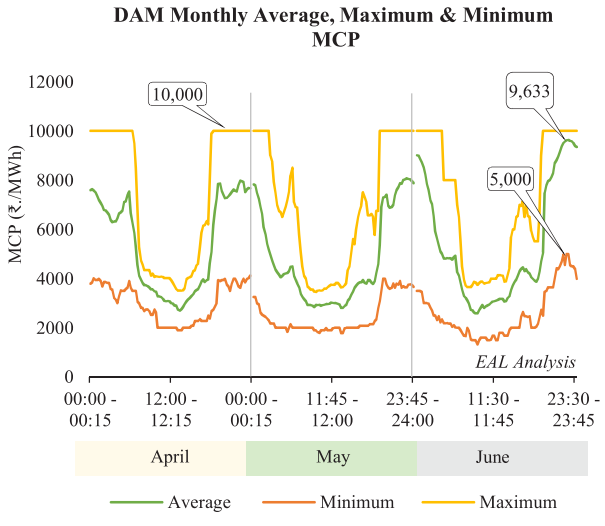


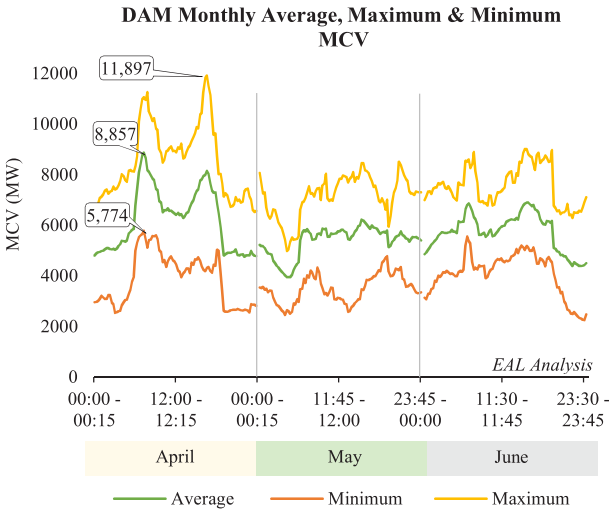
Power Market Overview & Analysis

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



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

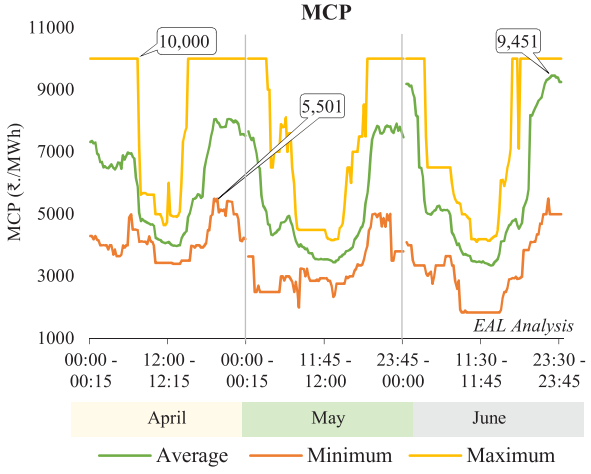




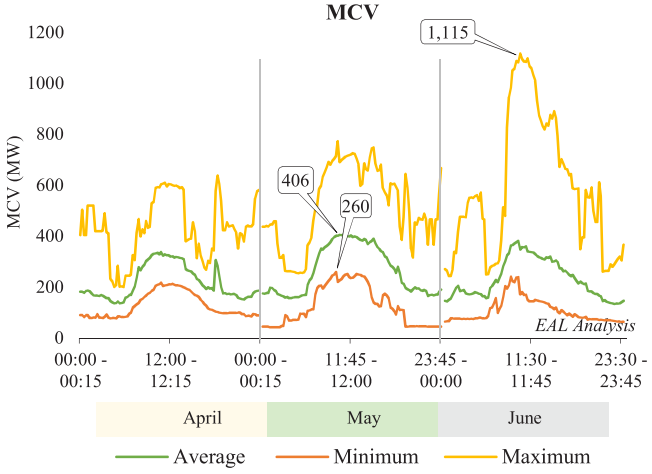
For more information Click here

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

G-DAM Monthly Average, Maximum & Minimum MCP

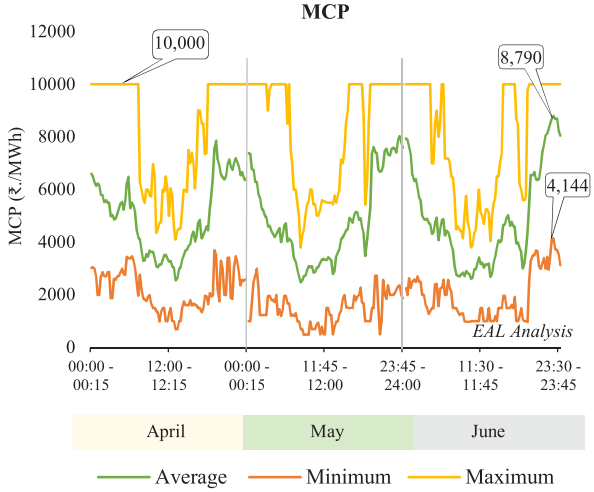


G-DAM Monthly Average, Maximum & Minimum MCV

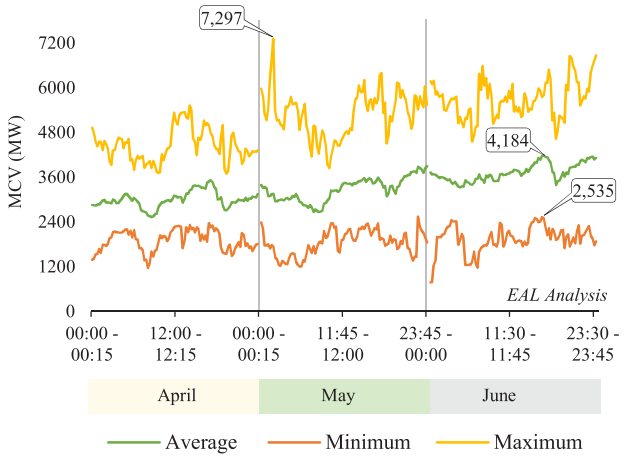


RTM - Market Clearing Price (MCP) & Market Clearing Volume (MCV)

RTM Monthly Average, Maximum & Minimum MCP

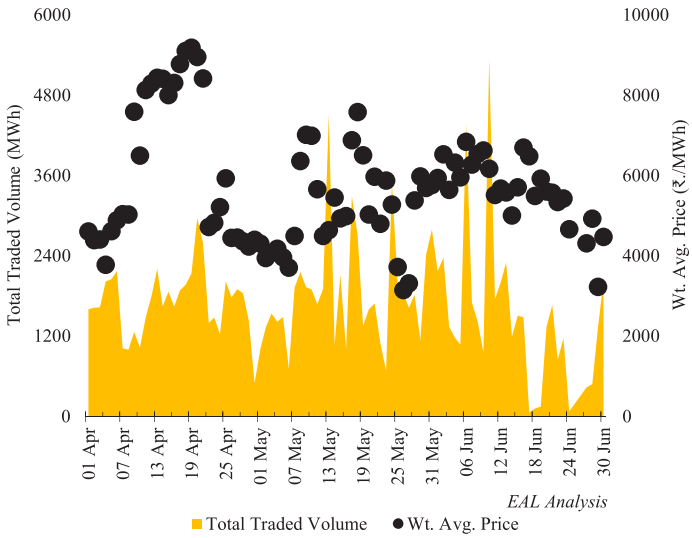


RTM Monthly Average, Maximum & Minimum MCV

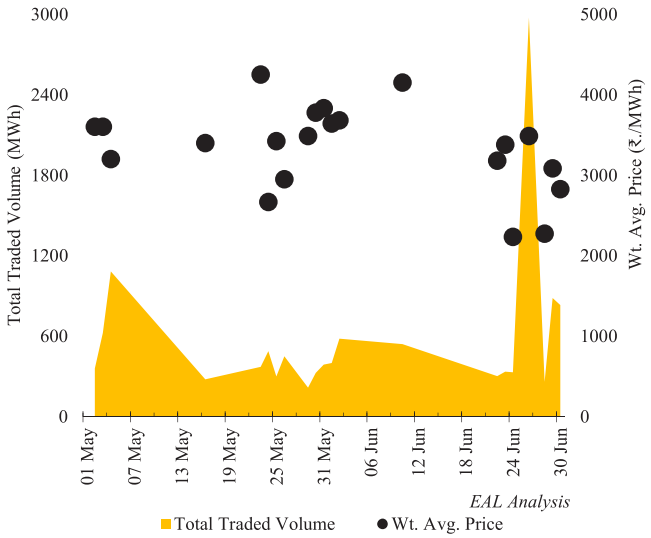


Green Term-Ahead Market (G-TAM)

Day-Ahead Contingency Transactions - Non-Solar



Day-Ahead Contingency Transactions - Solar



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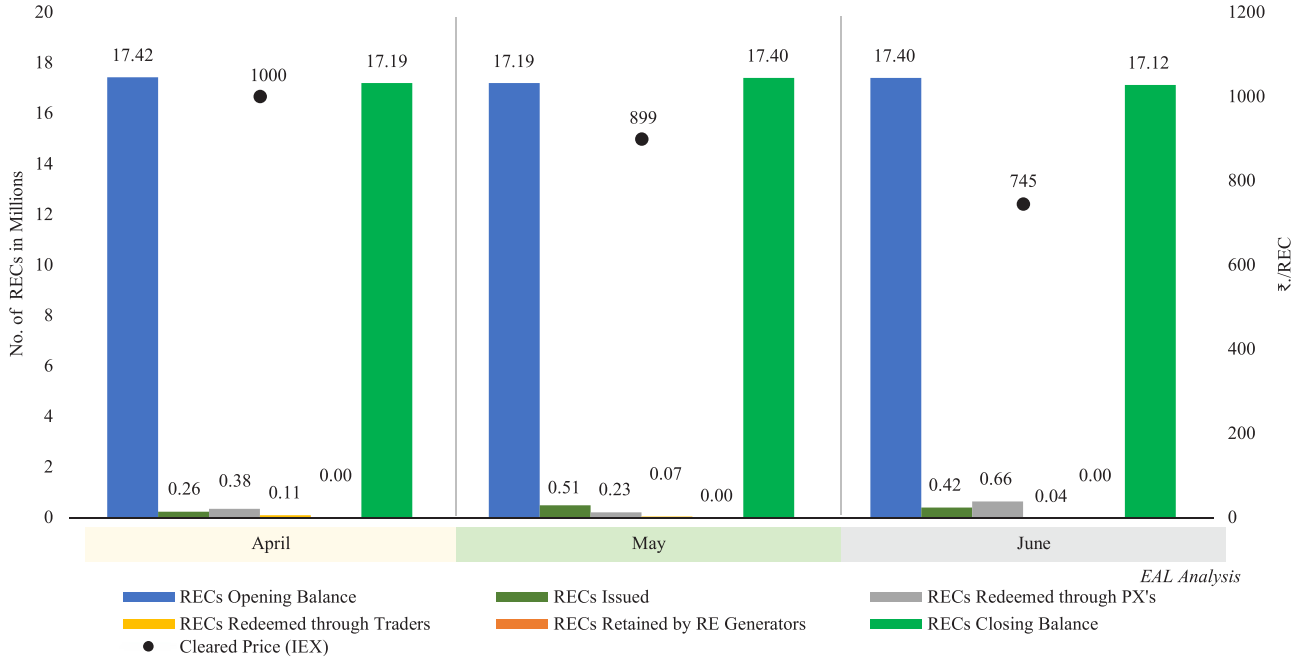
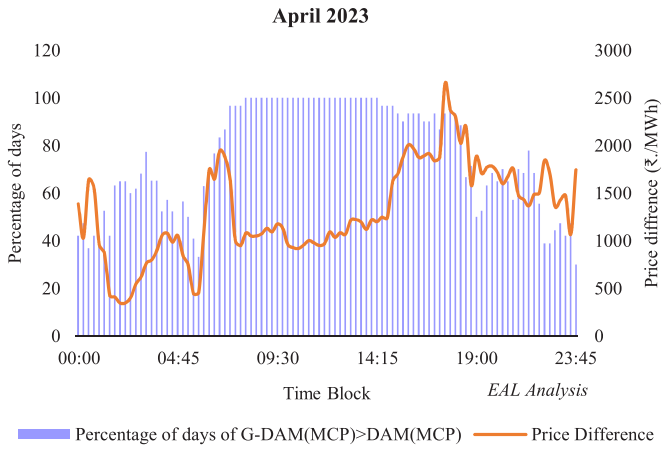
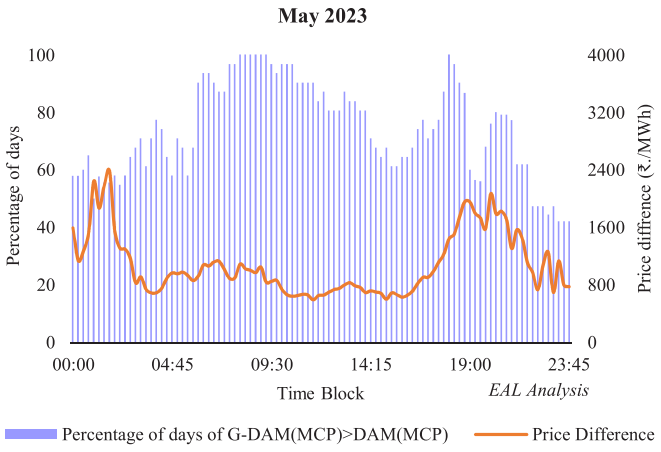
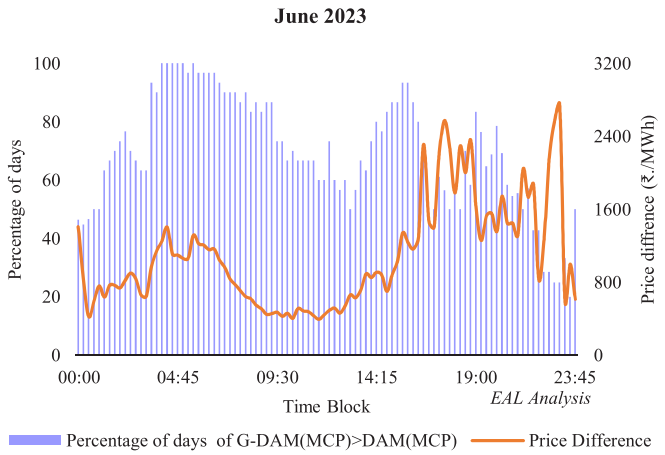
Renewable Energy Certificates (RECs)



Price Difference b/w G-DAM & DAM







EAL Analysis

- The analysis is based on comparison between the Average Price Difference of G-DAM and DAM, when price for G-DAM is greater than DAM.
- Average Price Difference of Rs. 1.20/kWh between G-DAM & DAM was observed during this quarter.
- Maximum Price Difference of Rs. 3.56/kWh was observed during 12:30 - 12:45 in the month of June.

For more information Click here

Regulatory & Policy Perspective

CERC (Sharing of Inter-state Transmission Charges and Losses) (2nd Amendment) Regulations, 2023 [Draft]

CERC notified draft on "Sharing of Inter-state Transmission Charges and Losses" on 17th March, 2023. The key highlights of the draft are mentioned below:

- **Objective:** To determine the Yearly Transmission Charges (YTC) in case of an inter-state Transmission system (ISTS) which has achieved deemed Date of Commercial Operation (CoD).
- **The YTC for the Inter-state transmission licensee which has achieved the deemed CoD shall be treated in the following manner:**
  - 20% of YTC shall be paid to the inter-state transmission licensee for a period of 6 months from date of deemed CoD or till commencement of actual power flow, which is earlier.
  - 100% of YTC shall be paid to the inter-state transmission licensee from 7th month till commencement of actual power flow if actual power flow does not commence within a period of 6 months from deemed CoD.
  - The above mentioned YTC shall be disbursed from monthly transmission deviation charges under third bill. In case of shortfall, the balance charges shall be recovered from charges collected under T-GNA. In case of further shortfall, balance charges shall be paid from Deviation and Ancillary Service Pool account under DSM Regulations.
  - If ISTS of an inter-state transmission licensee (say A) achieves deemed CoD due to delay in commencement of power flow of in its ISTS because of other inter-state transmission licensee (say B), then B shall pay 20% YTC of its transmission system or 20% of YTC of the transmission system of A, whichever is lower till its delayed ISTS system achieves CoD.
  - If ISTS of an inter-state transmission licensee (say C) achieves deemed CoD due to delay in commencement of power flow of in its ISTS because of an inter-state transmission licensee (say D), then D shall pay 20% YTC of the transmission system of C, till its delayed inter-state transmission system achieves CoD.
  - The reimbursement of transmission deviation charges to any user of ISTS shall be done in proportion to their share in first bill in the following billing month.
  - In case of ISTS under tariff based competitive bidding, first year shall commence from the date when the licensee starts receiving 100% of YTC or under Regulation 5 to 8 of the Principal Regulations.

EAL Opinion

- **Inadequate Revenue for the Inter-state Transmission Licensee to Carry out its Debt-service Obligations:** Proposed Clause 13(12)(a) in the draft document states, *"(12) For the cases other than those covered Clauses (3), (6) or (9) of Regulation 13 of these regulations, the YTC for the inter-state transmission system approved or declared as deemed CoD shall be treated as follows: (a) The inter-state transmission licensee shall be paid **20% of YTC** of its inter-state transmission system for a **period of six (6) months** from date of deemed CoD or till commencement of actual power flow, whichever is earlier."* (emphasis added)

  The debt component covers a major part of the capital cost. This is payable by the licensee to the banks/financial institutions in a timely manner. A payment of 20% of YTC may be insufficient for the inter-state transmission licensee for carrying out its debt-service obligations. It is recommended to increase the percentage of YTC to be paid to the licensee for the first six months, in a manner such that the licensee shall not face the risk of debt default just after the beginning of the deemed CoD.
- **CoD Delay Attributable to Third Party (Entity Responsible for the Development and Commissioning of ISTS other than the Generator) should be Attributable to the inter-state Transmission Licensee.** A delay in

the achievement of CoD of the inter-state transmission project may occur due to multiple reasons, which also includes those attributable to third parties. The delay due to the inactions or actions taken by the third party should be part of the agreement of the licensee with the third party (for example the EPC contractor). Since the transmission licensee should follow prudent contractual arrangement ensuring that risks attributable to third party directly involved in setting up the transmission system or its component, then the transmission licensee should be held accountable as its risks are covered under its agreement with the third party.

- **Recovery of Sufficient Charges from Deviation and Ancillary Services Pool Account:** Proposed Clause 13(12)(d) in the draft document states, *"In case an inter-state transmission licensee is responsible for the delay* ***(for any reason including the reason attributable to Force Majeure events)*** *in commencement of power flow in the ISTS of another inter-state transmission licensee which has achieved deemed CoD, inter-state transmission licensee of the delayed ISTS shall pay 20% of YTC of its transmission system OR 20% of YTC of the transmission system which has achieved deemed CoD, whichever is lower, till its delayed ISTS achieves CoD."* (emphasis added)

  It is not clear whether the inter-state transmission licensee shall pay the 20% of YTC charges to Regional Transmission Deviation Account or directly to the other inter-state transmission licensees whose system have achieved the deemed CoD. Clarifications are required for the same. The average transmission charges for two different transmission projects may vary. The inter-state transmission licensee (say A) which has achieved the deemed CoD specifically due to delay caused by another inter-state transmission licensee (say B) shall be paid the lowest of 20% of YTC of A (say YTCA) and 20% of YTC of B (say YTCB). If the YTCA comes significantly higher than YTCB, then A will recover very less amount as compared to the amount it will receive due to delay caused due to its own. This seems unfair for A whose project is delayed due to reasons associated with B. It is recommended to pay the amount of YTCA from licensee B to licensee A. If the licensee B is not able to fully pay the required amount, then rest of the amount can be paid to A from Regional Transmission Deviation Account or Deviation and Ancillary Services Pool Account.

- **Delay in CoD Attributable to Multiple Inter-state Transmission Licensee:** The draft document have not provided the provisions for the scenario where multiple inter-state transmission licensees are responsible for delay in CoD. Accordingly, for the particular scenario, following provisions should be included in the Regulation:
  - How the penalty attributable to the delay in achieving the CoD would be divided among the multiple Interstate transmission licensees?
  - How the penalties would be decided In case a part of these delayed transmission components achieve CoD, while the rest are yet to achieve the CoD?

- **CoD Delay Attributable to Force Majeure Event shall be used for Penalty:** The delay in achieving the CoD attributable to a Force Majeure event affecting the CoD of another inter-state transmission licensee or inter-state transmission licensee shall be considered as delay due to an uncontrollable factor. Accordingly such licensee should not be penalized into paying the 20% of YTC as applicable.

- **CERC jurisdiction on Intra-state transmission licensee:** Proposed Clause 13(12)(e) in the draft document states *"In case an intra-state transmission licensee is responsible for the delay (for any reason including the reason attributable to Force Majeure events) in commencement of power flow in the inter-state transmission system of an inter-state transmission licensee which has achieved deemed CoD, inter-state transmission licensee of the delayed inter-state transmission system shall pay 20% of YTC of the inter-state transmission system which has achieved deemed CoD, till its delayed inter-state transmission system achieves CoD."*

  The inter-state transmission licensee comes under the jurisdiction of their respective State Electricity Regulatory Commissions (SERCs). Accordingly, the proposed Clause seems to suggest that the inter-state transmission licensee should be liable to pay for the delay to inter-state transmission licensee in achieving the CoD. More details/clarification is required in the context of the jurisdiction over an inter-state transmission licensees.

CEA (Guidelines for Medium and Long-term Power Demand Forecast), 2023 [Draft]

CEA notified draft on "Guidelines for Medium and Long-term Power Demand Forecast" on 11th April, 2023. The key highlights of the draft are given below:

- **Objective:** As per the draft, the medium-term forecast should be prepared more than 1 year and up to 5 years while long-term forecast should be done at least for the 5 years and at least for next 10 years. The draft document suggests that the forecast should be prepared in consultation with all stakeholders, including industrial, agricultural, municipal corporations, drinking water departments, captive power plant owners and other departments involved in planning and implementing electrical schemes.

- **CEA suggested Forecasting methodology as follows:**

  According to draft document, the demand projection should be done at utility level. The foremost step proposed is analysing historical consumption data for each consumption category independently and taken into account the effects of new factors to determine the best future development tendencies. In addition to this, impact of specific Govt. policies, developmental plans and other emerging aspects should also be considered for medium-term forecast. The growth trends estimated under medium-term forecast is extrapolated further to estimate long-term forecast. The forecasting results obtained should be validated through at least one different method.

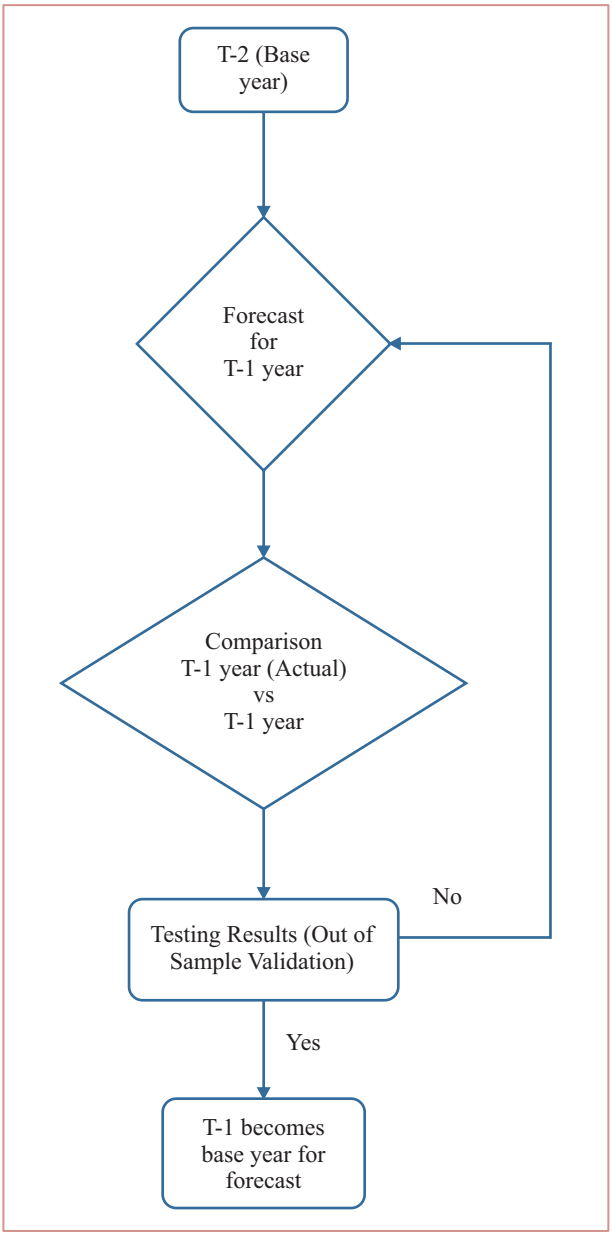


Figure 1: Forecasting methodology

- **Input Data that should be considered:**
  - Category-wise consumption data including Domestic, Commercial, Public Lighting, Public Water Works, Irrigation, LT Industries, HT Industries, Railways, Bulk Supply & Others.
  - Electricity consumption of Open Access consumers should be added if discoms had not accounted for such energy.
  - The input data should be collected for the past 10 years at least.
  - The unserved demand should be added category-wise as per the consumer mix profile of the concerned geographical areas.
  - The weather parameters (such as rainfall, temperature) should also be collected.
  - The past growth trends for T&D losses (in energy terms) should be considered separately.

- CEA has considered Partial End Use Method (PEUM) for forecasting electricity demand. Two statistical method is considered least square method and weighted average method. The document also suggested to estimate energy requirement of a state incident upon the ex-Bus of the generators. After that peak demand should also be forecasted by applying monthly/yearly load factor.

- In addition to this weather parameters are also considered separately which impact electricity demand. Advanced statistical tools like Multivariate Regression Analysis should be used for this purpose.

  The guidelines suggests granularity based on spatial and time. The forecasts should be prepared at the discoms/ state level at least, but more granular forecasts should be attempted at the zonal, circle, district, sub-station, and feeder/transformer levels if adequate granular level data is available. More granularity based on time should be work out. According to draft document forecasting should be carried out for at least three scenarios – Optimistic scenario, Business As Usual (BAU) scenario & Pessimistic scenario.

EAL Opinion

- **Harmonised Regulatory Framework for Electricity Demand Forecasting:** A publication by the Centre for Energy Regulation (CER), IIT Kanpur on "Regulatory Framework for long-term Demand Forecasting and Power Procurement Planning", (Singh et al., 2019)[1] emphasised the need for introducing/updating applicable regulations for demand forecasting and Power Procurement Planning (PPP). It was found that regulatory framework for the same differs across states with marked differences in terms of scope, horizon, methodological approach, responsible agency, periodicity etc. The proposed guidelines by CEA would help in bring about a harmonized regulatory framework to help coordinate this exercise in a bottom up manner enabling coordination and consolidation of the forecast for state, regional and national level.

- **Overlapping Long-term and Medium-term Forecasts:** Draft Clause A.1 states, *"The forecast should be prepared for medium-term (more than 1 year and **up to 5 years**) as well as for long-term **(more than 5 years)**."* (emphasis added)

  The methodological approach to medium- and the long-term forecast may differ. To ensure that the two methodologies are able to reproduce the respective forecast, the guidelines should ensure that there is a common overlapping year for which both medium-term as well as long-term forecast would be undertaken. Depending on the approach to forecast for the two types of horizon, the energy/peak-demand/demand profile from the two forecasts can be compared for the common year and thus be calibrated accordingly. The long-term forecast can thus cover a period of 5 years and above.

- **Consultation with State Planning Department:** Draft Clause A.4 states, *"The forecast should be prepared/reviewed/updated in consultation with all stakeholders such as industrial department, agricultural department, municipal corporation, drinking water department, captive power plant owners, state nodal agencies for renewable energies and any other department entrusted with planning and implementing any electrical energy intensive plan/scheme."*

  While undertaking the electricity demand forecasting at the discom and the state-level, it is important to have the perspective of necessary targets or plans set up by the state planning department of the respective states. Accordingly, consultation process should also include the state planning department.

- **Flexibility to Choose Base Year Test of Model Performance:** Draft Clause A.5 states, *"The base year for the forecast should ideally be taken as the two-year (T-2) preceding the year during which forecast exercise is being carried out. For example, if forecasting exercise is being done in 2022-23, then the base year for the forecast should be 2020-21. This is to be done to test the performance of the forecasting model by comparing the forecast results obtained for 2021-22 with actual available data (termed as Out of Sample Validation)."*

  The guidelines propose the base year for developing the forecasting model shall be T-2, if the exercise is being carried out during the year T. Since the exercise will be carried out at the discom level, which are in large number and are situated in diverse regions of the country, some discoms are likely to have insufficient amount of data available up to the year T-2. Thus one year flexibility to use data up to T-3 year for carrying out the exercise for the first time may be provided for as a one-time exception.

- **Change of Base Year:** Draft Clause A.6 states, *"The base year for the forecast should subsequently be changed to T-1 after testing the performance of forecasting model."*

  While the performance of the forecasting model will be tested using T-2 as the base year, the forecasting exercise for later years will be carried out by using T-1 as the base year. Since the original forecast will continue to be anchored to year T-2, change of base-year later to T-1 would be only a cosmetic and redundant exercise. It is suggested to retain T-2 as a base year to correctly reflect the underlying approach.

- **Consideration of Discom's Ownership:** Draft Clause A.7 states, *"Spatial Granularity - The forecasts should be prepared at the Discom/State level at least. In addition, forecast at more granular levels i.e. Zonal level, Circle level, District level, Sub-Station Level, Feeder/Transformer level should also be carried out in case of availability of adequate granular level data. Such granular forecasts would be more useful in power infrastructure planning. It*

[1] Singh et al. (2019), "Regulatory Framework for long-term Demand Forecasting and Power Procurement Planning", 2019. Centre for Energy Regulation, Indian Institute of Technology Kanpur. ISBN: 978-93-5321-969-7
https://cer.iitk.ac.in/assets/downloads/CER_Monograph.pdf

would also help in generating more revenues as the potential customers would be fascinated to set up their base in the areas where their power requirements are expected to be fulfilled and are already a part of the planning process."

Discoms within a state may be under ownership of public/private entities. It is noted that across most of the states, multiple discoms are owned by the respective state government[2]. It is also observed that most of the planning/forecasting for power procurement is undertaken in a consolidated manner for all the discoms under public ownership (often by the holding/trading company). Such disoms should be required to undertake exercise at the discom level to provide better visibility and enable further planning by the discoms. Furthermore, forecasting at more granular level (zonal/circle/district/sub-station etc.) may only be feasible if sufficient and reliable data with similar granularity is available. A predefined timeline, say 3 years, may be set for the discoms to begin the exercise at more granular level. The intervening period should be utilized to setup necessary database for the same.

- **Time Granularity for Medium-term and Long-term Forecast:** Draft Clause A.8 states, *"Time Granularity- The forecast should be worked out year-wise at least. In addition, month-wise/day-wise/hour-wise/time-block wise forecasts should also be done if adequate granular level data is available."*

  The guidelines have been made to carry out year-wise forecast at least on time granularity level for both medium-term and long-term. Depending on the methodological approach adopted for the long-term/medium-term forecast, the level of granularity may differ. For example, there could be annualized year-wise energy forecast with peak load forecast for the long-term (may be with variation for peak/off-peak months), whereas there may be time block based forecast for the medium-term. Such a flexibility in choice of granularity may be desirable and be incorporated in the guidelines.

- **Common Reference Optimistic, Business as Usual (Bau) and Pessimistic Scenario:** Draft Clause A.9 states, *" The forecast should be carried out for at least three scenarios – Optimistic scenario, Business As Usual (BAU) scenario & Pessimistic scenario."*

  To enable consolidation of the discom/state-level forecasts across different scenarios, a common framework to choose a set of assumptions for the Optimistic, Business As Usual (BAU) and Pessimistic scenarios may be adopted. Although it may not be feasible to suggest similar/same numerical values, but relative scale difference across key assumptions may help develop a national level forecast for the three scenario to some extent.

- **Flexibility to Choose the Methodology for Forecasting:** Draft Clause A.13 states, *"The long-term forecast should be based on further extrapolation of the growth trends estimated under medium-term horizon."* while A.14 states, *"The forecasting results obtained should be validated through at least one different method. Econometric Method should preferably be one of the methods adopted for forecasting"*. Also, Section C of the document is titled as 'Forecast Methodology (Partial End Use Method)'. Draft Clause C.8 states, *"The peak demand forecast of a Discom/State should be derived from the energy requirement figure by applying appropriate load factor…"*

  It is important to point out that at multiple places, the guidelines has emphasized application of PEUM as the primary method for forecasting. While the aim of the document seems to set the standards for forecasting at the discom/state level, restriction of choosing the forecasting methodology should be avoided. In fact, availability of alternate forecast methodologies would help the states/dicoms to learn from them and make an informed choice in later cycle of forecasts. The discom should thus be given the flexibility to adopt the approach for undertaking the medium-term and long-term forecast. In this context, the proposal for 'extrapolation of the growth trends' applied to the medium-term forecast to arrive at the long-term forecast is also not advisable. Depending on the availability of data, respective experience and merit of the methodology, the states/discoms may be allowed flexibility to choose one methodology as a primary one (e.g. econometric forecast) and use the other one (e.g. PEUM) for validation.

- **Inclusion of Banking:** Draft Clause B.2 states, *"The consumption categories should be identified as per the tariff structure prevailing in the respective Discoms. The broad categories are Domestic, Commercial, Public Lighting, Public Water Works, Irrigation, LT Industries, HT Industries, Railways, Bulk Supply, Open Access & Others."*

  Banking of power may cross over from one financial year to the other. Energy accounting towards the same should be considered and adjusted while finalizing historical data for demand forecasting.

[2]For example, in the case of Uttar Pradesh, there are five Government owned discoms, whereas one is privately owned.

- **Exclusion of 'Sale Outside the State':** Draft Clause B.4 state, *"The "Other" category should generally include energy consumption not fitting into any of the standard categories such as temporary connections consumptions, State Centre Category (as in Jammu & Kashmir) consumption, etc."*

  These guidelines do not refer to an important 'consumption' category, identified separately in some states, called 'sale outside the state'. It is important to highlight that data for such sales should be excluded from analysis as it pertains to 'consumption' in other states/discoms. Otherwise, it would result in double counting and affect the forecast of energy 'to be consumed' in a state/discom, and would also influence the estimation of overall network losses as such sales would only account towards inter-state/intra-state transmission losses.

- **Category-wise Unserved Demand:** Draft Clause B.5 states, *"As far as possible, the unserved demand should be added category-wise as per the consumer mix profile of the concerned geographical areas. In case of unavailability of these details, such demand should be added to the "Others" category."*

  The category-wise unserved data is not captured across discoms due to mixed feeders and lack of appropriate metering. In contrast, unserved demand across a discom is usually captured in a structured manner and can be incorporated for the discom level forecast. The guidelines should highlight the need to capture category wise unserved demand as well as load profile, though a larger sampling-based approach. Such data should be collected and reported on a block-wise basis across the year. This would help incorporation of such information in electricity demand forecast in the future.

- **Impact of Weather Data:** Draft Clause B.6 states, *"The weather parameters (such as rainfall, temperature) should also be collected for arriving at the forecast range."* The PEUM, in its basic form, does not directly use weather data in arriving at a forecast. Econometric methods are more suitable for capturing influence of weather and other such parameters. Further, given spatial diversity of weather across discom, granular forecast (at district, control area, feeder level etc.) would capture this impact in a better manner. Nevertheless, discoms should implement a framework for capturing detailed weather parameters through substation level sensors, possibly implemented through a third party and ensure its operational effectiveness. This data would be useful for more reliable forecasts in future incorporating impact of weather parameters.

- **Data Availability and Accessibility in the Public Domain:** Discoms should be mandated to compile identified data useful for developing demand forecast and make it accessible through its portal so that other independent forecasts can be developed and provide better insights to adoption of a suitable methodology in future.

- **CEA's Dashboard for Consolidating Discom/State-level Forecasts:** The medium and long-term forecasts shall be submitted to CEA and should be available for further validation by stakeholders including academic institutions. CEA may develop a common dashboard to provide access to individual and consolidated forecasts at state-regional/national level.

- **'Growth Trend' for Granular Forecasting?:** Draft Clause B.6 states, *"Note – In case of more granular forecasting exercise, the annual consumption growth rate of each month/day/hour/time-block, as per applicability, could be analysed separately."*

  While it has been mentioned in the guidelines that granularity of forecast would depend on availability of data (for example, month-wise, day-wise, hour-wise, block-wise data, etc.), it is neither advisable to apply 'trends/growth rate' on daily, hourly or block-wise forecasts as economics trends and seasonalities do not follow calendar with such a granularity.

- **Time Series Data for Emerging Aspects:** Draft Clause C.3 states, *"The impact of emerging aspects expected in future should be factored in additionally after arriving at the forecast on the growth rates estimated on the past time series data."*

  For emerging aspects expected in the future, there will not be any past data, hence there will not be any quantitative trend for the same. It will be complicated to include the impact of emerging aspect on present forecast.

- **Impact of Energy Efficiency and Incorporating Achieved Targets for Policies:** Draft Clause C.4 states, *"The impact of energy efficiency should not be considered additionally in most of the cases as such impacts are already captured intrinsically in the past time series data…"*.

  It is suggested that Energy efficiency should be considered while forecasting for later years. Even if past time series data does indicate a reduction in energy use, it is important to continue monitoring and evaluating the impact of

energy efficiency measures over time, as the effectiveness of these measures may change as technology advances and scope for further improvement is identified.

In context of impact of major Government policies, it is suggested that apart from Government policy targets, realistic policy targets may also be adopted and these be fine-tuned with progress thereof. Long-term electricity demand forecasting under taken by EAL, IIT Kanpur for the states of Uttar Pradesh, Rajasthan as well as Chhattisgarh have made such[3,4,5].

- **Provisions for Un-metered Connections for Agricultural Loads:** A significant portion of electricity sold by discom was un-metered (particularly for agriculture, lifeline tariff, street lamp, etc.). A greater proportion of the same still remains un-metered. The guidelines should specifically provide for treatment of such un-metered consumption. This would make category-wise forecast, for such categories, to be a challenging task.

- **Integration of Weather Parameters with Partial End use Method:** Draft Clause C.10 states, *"The electricity demand depends on weather conditions also. In the traditional PEUM, weather parameters are not considered separately as those are assumed to be inherent in the past energy consumption data. However, weather parameters should be considered separately while developing more than one forecasting scenario."*

  How is it proposed to consider weather parameters separately in forecasting scenarios while the PEUM itself does not incorporate the weather-related aspects in an explicit manner? Unless the methodology itself is modified to take weather parameters into account, creation of such scenarios will not be possible.

- **Distribution of Impact of Emerging Aspects:** Draft Clause D.2 states, *"If the targets are not segregated at annual level or no definite trends are anticipated, then an exponential trend with more impact in the later years should be considered."*

  Adoption of 'exponential trend' in the absence of a 'definite trend' would be erroneous as this would lead to over estimation of forecast if the underlying model does not identify the same. The choice of trend should be based on the forecasting model, preferably estimated using an econometric model.

- **Approach for Medium-term Forecasting:** Box D.1 states, *"The approach discussed here for considering impact on power demand due to emerging effects is target based that is normally available on yearly basis. In such cases, the month/day/hour/time-block wise demand impact assessment should be done by arriving at the annual impact assessment first and then spreading it over to each month/day/hour/time-block appropriately."*

  The procedure to spread the annual impact due to emerging aspects to each month/day/hour/time-block shall be clarified. It seems a number will be given for each day of every discom/state. This will not be correct approach to do medium-term forecasting and the above Clause should be modified accordingly.

- **Exclusion of Billing Efficiency from Distribution losses:** Box E.1 states, *"If compared with the concept of Aggregate Technical & Commercial (AT&C) Losses, then Distribution Losses for the power demand forecasting exercise should include Technical as well as Billing Efficiency losses but exclude Collection Efficiency Losses."*

  The billing efficiency is not a reflection of consumption pattern but the commercial performance of the discoms. It does not play a role in electricity demand forecasting. Thus in place of AT&C losses, T&D losses should be considered for the forecasting.

- **Estimation of Un-metered Consumption:** Draft Clause E.2 states, *"Distribution losses of a Discom should be calculated by subtracting total electrical energy billed to all consumers from total electrical energy purchased by Discom from all sources."*

  While the distribution losses shall be calculated by subtracting energy billed to all consumers from total electrical

[3] Singh et al. (2019), "Regulatory Framework for long-Term Demand Forecasting and Power Procurement Planning", 2019. Centre for Energy Regulation (CER), Indian Institute of Technology Kanpur. ISBN: 978-93-5321-969-7
https://cer.iitk.ac.in/assets/downloads/CER_Monograph.pdf

[4] Singh, Anoop (2021), long-term Energy/Load Forecasting and Power Procurement Planning: Case Study of Uttar Pradesh and Chhattisgarh, Centre for Energy Regulation (CER), Indian Institute of Technology Kanpur.
https://cer.iitk.ac.in/assets/downloads/FOR_CBP14/presentations/CBP14_PPT_anoops@iitk.ac.in_LTDF.pdf

[5] Singh, Anoop (2022), Project Summary Report on Rajasthan Energy Scenarios for 2030 and 2050, Centre for Energy Regulation (CER), & Energy Analytics Lab (EAL), Indian Institute of Technology Kanpur.
https://eal.iitk.ac.in/CER_EAL_IITK_Project_Summary_Report_of_LTDF_for_Rajasthan.pdf

energy purchased by the discoms as per the guidelines, it is also important to keep in mind that the agricultural consumption comes under the category of un-metered consumption, which cannot be measured or recorded. CER recommends to add a separate section in order to elaborate on the estimation of un-metered consumption for the forecasting purpose to conduct month-wise/day-wise/hourly/block-wise forecasting.

This is another reason why the PEUM method should not be used as a primary method for forecasting.

- **Impact of Rooftop Solar and Solarised Pumps on Network Losses:** While rooftop solar and solar pumps have not made significant contribution to the electricity demand in the past, it is expected to play an important role in future. Due consideration should be given to their impact while forecasting electricity demand in future.
- **Estimation of Total Peak Demand from Category-wise Peak Demand:** It is important to point out that if the peak demand is being calculated category-wise which seems so as per Clause G3, G4 and G5, then it will not be possible to easily arrive at total peak demand unless coincidental nature of peak demand of all consumer categories is ascertained.
- **Conflicting Philosophies for Optimistic and Pessimistic Scenarios:** Annexure III of the document shows a table explaining the philosophies of optimistic, BAU and pessimistic scenarios. In the table, the impact of Government Targets vs impact of rest of the parameters on the demand seems to be conflicting with each other. In the absence of such consistency, the states shall define the three scenarios based on their own judgement, which will result in inconsistency of forecast-terminology among discoms/states. The philosophy of three scenarios, thus shall be defined clearly to ensure consistency across states.

CEA (Guidelines for Resource Adequacy Planning Framework for India), 2023

Ministry of Power (MoP) notified "CEA (Guidelines for Resource Adequacy Planning Framework for India)" on 28th June, 2023. The key highlights of the draft are given below:

- MoP, in consultation with Central Electricity Authority (CEA) has issued 'Guidelines for Resource Adequacy (RA) Planning Framework for India'. These guidelines are to be followed by the institutions and stakeholders such as CEA, NLDC, RLDCs, SLDCs, DISCOMs, SERCs/JERCs, etc. to ensure sufficient tie up of capacities to meet RA requirements over different time horizons.
- RA has been defined as *'tying up sufficient capacity to reliably serve expected demand of the consumers in the DISCOMs license area in a cost effective manner'*. Important aspect of the resource adequacy planning is to ensure the availability of adequate generation capacities, round the clock to reliably serve demand under various scenarios. The resource adequacy framework lays down the optimal capacity mix to meet the projected demand at minimum cost.
- Important definitions:
  a. **Planning Reserve Margin (PRM):** It is represented as reserve generation capacity in excess of peak load forecast as a percentage of peak load forecast.
  b. **Loss of Load Probability (LoLP):** Measure of probability that a system's load will exceed the generation and firm power contracts available to meet that load in a year.
  c. **Expected Energy Not Served (EENS):** Expected amount of load (MWh) that may not be served for each year within the planning period.
  d. **Net Energy Not Served (NENS):** Total expected load shed due to supply shortages (MWh) as a percent (%) of the total system energy.
  e. **Firm Capacity:** Amount of power a generator can reliably provide.
  f. **Capacity Credit:** Firm capacity expressed as a percentage of nameplate capacity.
- There will be four types of plans which will be implemented under the framework:
- **Long-term National RA Plan (LT-NRAP):** CEA shall publish LT-NRAP report for 10 year horizon which will be updated annually. The report will include the following:

a. National-level PRM

b. Optimal generation mix for next 10 years

c. Capacity credits of different power generation resources on a regional basis

d. State/UT's contribution towards national peak

- The process for the calculation of economically optimal PRM (Figure 2) is recreated in the chart shown below: The key highlights of the draft are given below:
- It is important to note that at the economically optimal PRM, the marginal cost of reducing load shed is equal to the value of lost load.
- **Short-term National RA Plan (ST-NRAP):** NLDC shall annually publish a one-year look ahead ST-NRAP report which will include the following:

  a. Demand forecasts

  b. Resource availability based on under construction status of new projects

  c. Planned maintenance schedules of existing stations

  d. Station-wise historic forced outage rates

  e. Decommissioning plans

- To conduct the study of LT-NRAP and ST-NRAP, STU/SLDC on behalf of the distribution licensees in the state shall provide the details regarding demand forecast (peak and energy requirement) for 10 years, assessment of existing generation resources, etc. to CEA and NLDC.
- **Long-term Distribution Licensee RA Plan (LT-DRAP):** Each distribution licensee shall undertake LT-DRAP for a 10 year horizon on annual rolling basis to meet their own peak load and electrical energy requirement. Based on the share in national peak demand provided in LT-NRAP, each licensee shall plan to contract the capacity that will be computed as:

  Resource Adequacy Requirement (RAR) (Demand Side) = Contribution to forecasted national peak demand * (1 + PRM) The demand side RAR will be matched with the supply side RAR (the overall sum of product of generation capacities and their respective capacity credits for all type of generation portfolios) to get the sufficient capacity for that particular area of supply of the licensee. The LT-DRAP prepared by respective distribution licensees shall be vetted/validated by the CEA and subsequently be submitted to SERC/JERC for their approval.

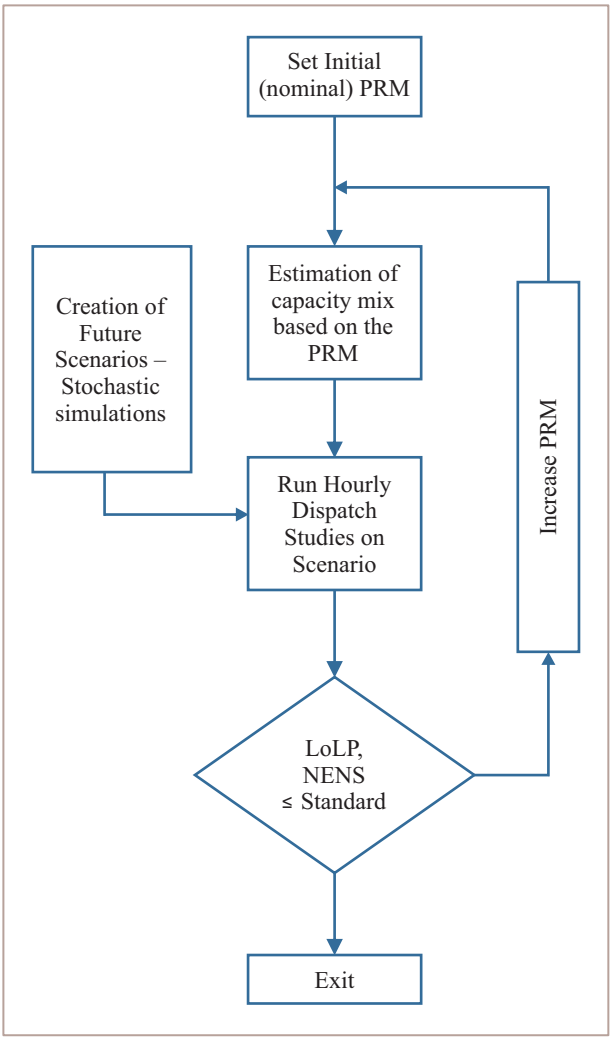


Figure 2: Calculation of economically optimal PRM

It will be required to maintain at least 75% of required capacities in LT-DRAP to be met through long-term contracts.

The approval process by the SERC/JERC will be followed by the submission of details of contracted capacities by discoms to the respective STU/SLDC. The capacities will be aggregated at state level by STU/SLDC and will be shared to the respective RLDC. The capacities will be aggregated at regional level by RLDC and will be shared to the NLDC. NLDC shall aggregate the capacities at the national level and will compare the same with ST-NRAP to identify shortfall for the next year. The shortfall will be communicated by NLDC to SERC/JERC for compliance or facilitate a national-level auction for the balance capacity with participation from distribution licensees with capacity shortfall.

- **Short-term Distribution Licensee RA Plan (ST-DRAP):** The STU/SLDC shall prepare one-year look ahead ST-DRAP on an annual basis based on LT-DRAP results. The ST-DRAP shall be reviewed by SLDC on a daily, monthly or quarterly basis based on actual availability of generation resources. The timeline of the RA exercise is shown in the figure below[6]:
- The timeline of the RA exercise (Figure 3) is shown in the figure below:

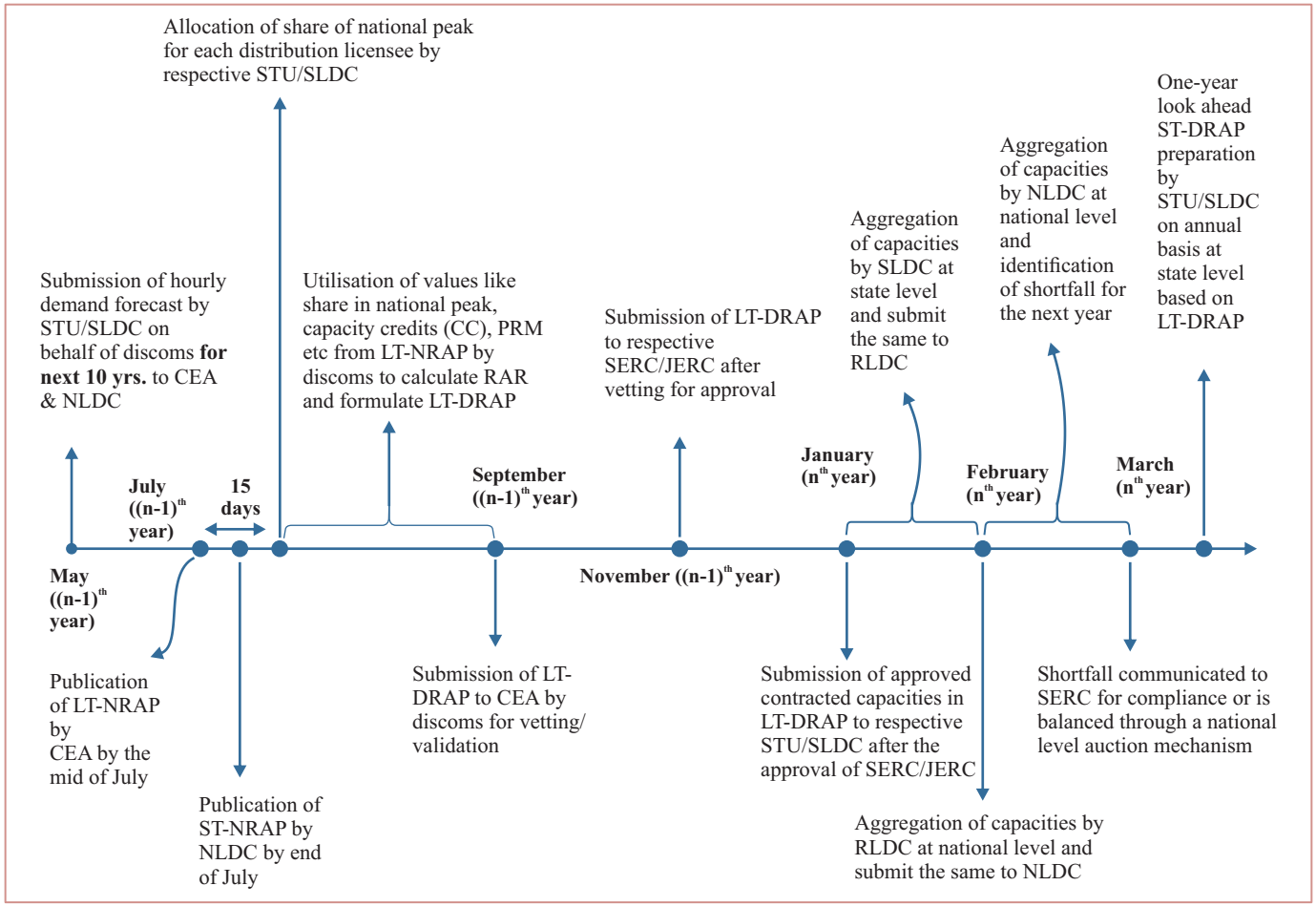


Figure 3: The timeline of the Resource Adequacy exercise

EAL Opinion

- **Necessity of Resource Adequacy Framework:** The overall objective of Resource Adequacy (RA) framework is to avoid demand-supply mismatch, ensure system security and reliability at the national level. Sufficient amount of power supply coupled with demand response framework and sharing of inter-state and inter-region power should be adopted to meet the peak demand reliably.

  Power procurement cost is a major part of the RA study. PPP and contracts typically have a long-term horizon and hence, need to be worked out well in advance, based on reliable and dependable forecast. CER, IIT Kanpur carried out a research on the importance of these aspects and published a book on *"Regulatory Framework for Long-term Demand Forecasting and Power Procurement Planning"*[7], highlighting the need for a regulatory framework for the

[6] Please note that the terminology used by EAL for the target year is **"nth year"** whereas **"(n-1)th year"** is the year in which forecasting exercise is being carried out for that target year. Following the standard approach to identify the target block, we differ from the notations given in the CEA **"Guidelines for Resource Adequacy Planning Framework for India"** and have adopted the terminology as shown in the timeline. The reason to avoid the use of terminology as mentioned in the document is to indicate other years in reference to the target year, thus adding more clarity in the understanding of the timelines.

[7] 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

same. CER and EAL, IITK have undertaken LTDF and PPP studies for the states of Uttar Pradesh as well as Chhattisgarh and have also undertaken LTDF for the state of Rajasthan and Gujarat. Apart from this, CER/EAL have contributed with their opinion to MPERC's *"Power Purchase and Procurement Process Regulations"*[8], and APERC's *"Terms and Conditions for short-term procurement/sale of power Regulation, 2021"*[9].

Given the experience of CER and EAL in carrying out LTDF and PPP 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 is possible through RA.**

- **Resource Adequacy Vs Generation Adequacy:** Clause 1(2) states, *"Resource Adequacy means tying up sufficient capacity to reliably serve expected demand of the consumers in the DISCOMs license area in a cost effective manner…"*.

  Given the fact that volatility in electricity prices have been witnessed in the recent years, some of preliminary analysis by EAL[10] suggests that demand response could have played an important role in addressing the price spikes. If we view the price spike only from the context of capacity addition, one would end up recommending even higher capacity to meet the growing demand and to address such kind of situation in the future, However, it is highlighted Demand Side Management (DSM) measures including demand response can contribute to address the demand supply imbalance in the short run.

- **Implementation of Alternate Approach to Demand Forecasting:** The implementation of LT-NRAP and ST-NRAP is to be preceded by the submission of demand forecast by the STU/SLDC on behalf of their respective discoms. The methodological approach to load forecasting may vary across discoms/states due to differing data availability, seasonal impact on demand, etc. Studies carried out by CER and EAL for the states of Chhattisgarh, Rajasthan and Uttar Pradesh highlight the evolution of methodological approach for load forecasting.[11]

- **Necessity of Block-wise Demand Forecast:** Clause 3(3) states, *"The hourly demand forecasts used by CEA and NLDC shall be aligned with the projections furnished by individual Distribution Licensees to CEA and NLDC..."* The system operation and market products for the Indian power sector are implemented on a 15 minute time block basis. Furthermore, greater penetration of VRE requires better visibility across granular time scale which could potentially improve demand forecasting and reduce forecasting errors.[12] Hence, the RA study should be implemented for the block-wise demand forecast instead of hourly demand forecast. Although in the RA Guidelines, it provides for that forecast as per the availability of demand and RE generation data. This approach gives precedence to hourly forecast over the block-wise forecast.

  Alternatively, the RA should have 15 minute forecast for the yearly data & higher time block of 30 minute/60 minute in case of unavailability of data. In the absence of the same, most of the RA studies would be tilted to hourly forecast making it even less relevant for such studies in future, when more data over 15 minute basis may be available.

- **Overlapping Timelines to Conduct Tariff Determination Exercise and LT-DRAP Approval by ERCs:** Clause 3(7)(2) states, *"…the plan LT-DRAP along with details for meeting the RAR of national peak for the utility may be submitted to SERC/JERC by the month of November for the period starting from the month of April in the subsequent year for their approval..."* while Clause 3 (10) states, *"The Distribution Licensee shall submit the details of the contracted capacities for the ensuing year for meeting RAR of national peak to the respective STU/SLDC after approval of respective SERC/JERC by the month of January"*.

[8] 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

[9] 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

[10] Refer the EAL Newsletter. https://eal.iitk.ac.in/assets/docs/power_chronicle_vol_5_issue_1.pdf

[11] Singh, Anoop (2021), long-term Energy/Load Forecasting and Power Procurement Planning: Case Study of Uttar Pradesh and Chhattisgarh, Centre for Energy Regulation (CER), Indian Institute of Technology Kanpur. https://cer.iitk.ac.in/assets/downloads/FOR_CBP14/presentations/CBP14_PPT_anoops@iitk.ac.in_LTDF.pdf

[12] The extensively discussed '5 Minute Framework' holds the possibility of future implementation.

The timelines for approval of tariff generally starts around the end of November for most of the states. With January being the deadline of submission of LT-DRAP by discoms to their respective STU/SLDC, the Commission would likely be engaged in the approval of tariff petition and may find it challenging to undertake the process of approval in parallel. It is suggested that the process of approval of LT-DRAP should be implemented well in advance before filing of the tariff petition. This would also ensure that the tariff petition also incorporates any relevant inputs from LT-DRAP. Singh et al. (2019)[13] recommended that the regulatory framework would thus, for PPP should adopt a separate exercise for LTDF and PPP and before the approval of ARR and tariff determination.

- **Uncertainty Among Discoms due to National Level Auction Mechanism:** Clause 3(10) states, *"In case of shortfall, NLDC shall either communicate the shortfall to the SERC/JERC for compliance or facilitate a nationallevel auction for the balance capacity with participation from distribution licensees with capacity shortfall. The contracting for the balance capacity shortfall shall be completed by the month of March prior to the start of the delivery year (1st April)..."*

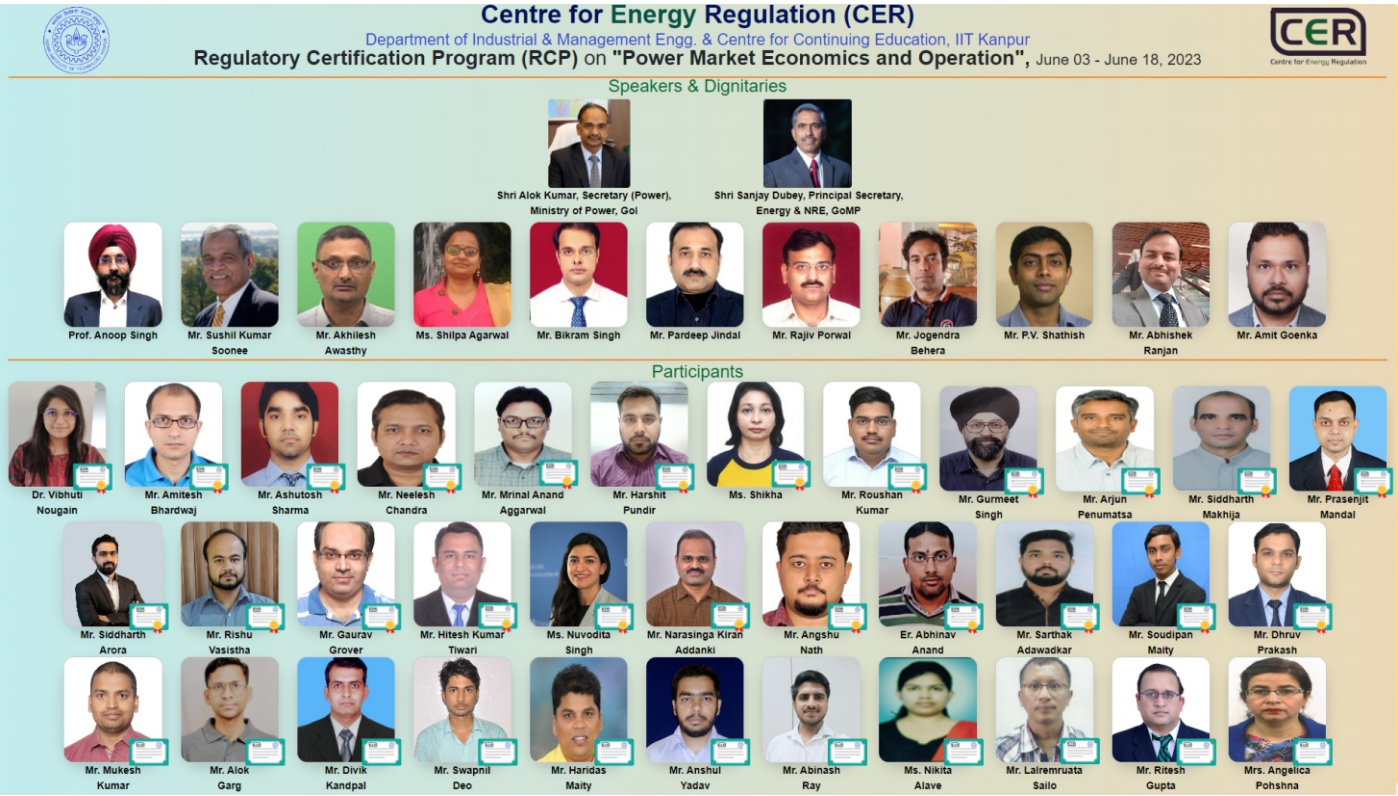
  The shortfall in the resource adequacy plan will be notified in the month of March of the n^{th} year whose plan is to be submitted for approval in November of $(n-1)^{th}$ year. By this time, the tariff petition would have already been submitted by the distribution licensees to the SERCs/JERCs. The notification of shortfall in RA by the month of March for the year beginning April may lead to a panic buy to procure ST capacity and that would adversely affect the market outcome for the distribution licensees.

- **Standard Terminology for Numbering of Target Year:** The detailed timeline as shown in the RA guidelines has labelled **'n+1'** as the target year for which the forecasting is to be done. The standard terminology should be to refer the target year as **'n'** instead of something like **'n-1'** or **'n+1'**. The reason to avoid the use of terminology as mentioned in the document is to set other years in reference to the target year, thus adding more clarity in the understanding of the timelines.

[13] Singh et al. (2019), "Regulatory Framework for long-term Demand Forecasting and Power Procurement Planning", 2019. Centre for Energy Regulation (CER), Indian Institute of Technology Kanpur. ISBN: 978-93-5321-969-7
https://cer.iitk.ac.in/assets/downloads/CER_Monograph.pdf

EAL News

Regulatory Certification Program



CER in association with EAL organised Regulatory Certification Program on "Power Market Economics and Operation" from 3rd June, 2023 to 18th June, 2023. The program was designed to understand the evolution, economic operation, regulatory structure of power market, PPP, its products and its role in the Indian power market. This program was conducted under the aegis of the Centre for Continuing Education, IIT Kanpur. Shri Sanjay Dubey (Principal Secretary , Energy & NRE, Govt. of Madhya Pradesh) graced the inaugral session on 3rd June, 2023. The speakers included Mr. Akhilesh Awasthy (Former COO, HPX; Currently Partner with Lantau Group India Pvt. Ltd.), Dr. Anoop Singh (Professor, IITK), Ms. Shilpa Agarwal (Jt. Chief (Engg.), CERC), Mr. Bikram Singh (Exe. Vice President, PTC India Ltd.), Mr. Rajiv Porwal (Executive Director, Grid India), Mr. Abhishek Ranjan (Sr. Vice President, ReNew Power) amongst many more. The valedictory session have been conducted under the auspices of Shri Alok Kumar (Hon'ble Secretary, MoP) on 24th June, 2023. For further program details including program duration, key topics, please visit https://cer.iitk.ac.in/index.php/OnlineLearningTool/Landing_Page_category3/?id=2

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