REPORT

ON

RESOURCE ADEQUACY FRAMEWORK

JUNE 2023

Forum of Regulators

केन्द्रीय विद्युत विनियामक आयोग
CENTRAL ELECTRICITY REGULATORY COMMISSION

सत्यमेव जयते

के वि वि आयोग
CERC

Indu Shekhar Jha
Member

No.:RA-11018(11)/1/2020-CERC
Date: 19th June, 2023

To

The Chairperson
Forum of Regulators (FOR)

Subject: Working Group Report on Resource Adequacy Framework

Dear Sir,

India is aiming to install 500 GW of non-fossil fuel capacity comprising primarily of renewable energy (RE) by 2030. Between FY 2015 and FY 2023, the RE capacity has increased manifold from 40 GW to 125 GW. The demand for electricity has also been increasing exponentially, with peak demand touching 223 GW in June, 2023. All this has brought in focus the need for a robust resource adequacy (RA) framework that ensures adequacy of resources to meet demand in all time horizons.

The FOR, in its 72nd meeting held on 17th August 2020, decided to constitute a Working Group on Resource Adequacy under my chairmanship with Chairpersons of UPERC, TNERC, PSERC, KERC, WBERC, OERC, UERC as Members, and Chief RA, CERC as Convenor. The scope of the Working Group was to *inter alia* assess RA requirement in states in the wake of RE expansion in the country and to formulate necessary regulatory framework for Resource Adequacy.

The Working Group held seven meetings and finalised the report outlining the recommended framework of Resource Adequacy for the States. The Group felt that having a well-designed RA framework would be important to scale up renewable in the grid while ensuring grid reliability in a cost-effective manner.

On behalf of the Working Group, I am pleased to submit herewith the report on **"Resource Adequacy Framework"** for consideration of the Forum of Regulators.

Yours sincerely,

(I. S. Jha)
Member, Central Electricity Regulatory Commission
and Chairperson of the Working Group

तीसरी मंजिल, चन्द्रलोक बिल्डिंग, 36, जनपथ, नई दिल्ली-110 001
3rd Floor, Chanderlok Building, 36, Janpath, New Delhi-110 001
Phone : 91-11-2375 3912 Fax : 91-11-2375 3923, E-mail : isjha@cercind.gov.in

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Abbreviations

APDCL	:	Assam Power Distribution Company Limited
BESS	:	Battery Energy Storage System
CC	:	Capacity Credit
CEA	:	Central Electricity Authority
CERC	:	Central Electricity Regulatory Commission
CER-IITK	:	Center for Energy Regulation, Indian Institute of Technology Kanpur
CH	:	Chhattisgarh
CPD	:	Coincident Peak Demand
CPP	:	Captive Power Plant
CTU	:	Central Transmission Utility
DER	:	Distributed Energy Resource
DRAP	:	Discom Resource Adequacy Plan
DSM	:	Demand Side Management
EA	:	Electricity Act 2003
ELCC	:	Effective Load Carrying Capacity
ENS	:	Energy Not Served
EPS	:	Electric Power Survey
ESS	:	Energy Storage System
EV	:	Electric Vehicle
FOR	:	Forum of Regulators
FY	:	Financial Year
GW	:	Gigawatt
IC	:	Installed Capacity
IEGC	:	Indian Electricity Grid Code
IEX	:	Indian Energy Exchange

IRP	:	Integrated Resource Plan
ISO	:	Independent System Operator
kW	:	Kilowatt
LBNL	:	Lawrence Berkeley National Laboratory
LDC	:	Load Duration Curve
LED	:	Light Emitting Diode
LOLP	:	Loss of Load Probability
LT	:	Long-Term
MNRE	:	Ministry of New and Renewable Energy
MOP	:	Ministry of Power
MP	:	Madhya Pradesh
MT	:	Medium-Term
MU	:	Million Unit
MW	:	Megawatt
MYT	:	Multi Year Tariff
NERC	:	North American Electric Reliability Corporation
NEP	:	National Electricity Plan
NENS	:	Normalised Energy Not Served
NLDC	:	National Load Dispatch Center
NRAP	:	National Resource Adequacy Plan
OA	:	Open Access
PEUM	:	Partial End Use Method
PLF	:	Plant Load Factor
PPA	:	Power Purchase Agreement
PRM	:	Planning Reserve Margin
PSH	:	Pumped Storage Hydro
PXIL	:	Power Exchange India Limited

RA	:	Resource Adequacy
RE	:	Renewable Energy
REPOSE	:	Renewable Energy Procurement Optimization and Smart Estimation
RLDC	:	Regional Load Dispatch Center
RPO	:	Renewable Purchase Obligation
RTI	:	Research Triangle Institute International
SAREP	:	South Asia Regional Energy Partnership
SERC	:	State Electricity Regulatory Commission
SLDC	:	State Load Dispatch Center
ST	:	Short-Term
STU	:	State Transmission Utility
TOR	:	Terms of Reference
US	:	The United States of America
USAID	:	United States Agency for International Development
vRE	:	Variable Renewable Energy
WBSEDCL	:	West Bengal State Electricity Distribution Company Limited
WG	:	Working Group
WR	:	Western Region
YoY	:	Year-on-Year

1 Background

The Forum of Regulators (FOR) was constituted vide Notification dated 16 February 2005 in pursuance of the provision under section 166(2) of the Electricity Act 2003 (EA or Act). It consists of the Chairperson of the Central Electricity Regulatory Commission (CERC) and Chairpersons of State Electricity Regulatory Commissions (SERCs). The Chairperson of CERC is the Chairperson of the Forum.

The FOR, in its 70th meeting held on 31st January 2020, deliberated on the issues of resource adequacy (RA) and its important aspects such as demand forecasting, mapping existing supply-side resources, and identifying economical and environmentally viable options for procuring power to meet forecasted additional demand. In its 72nd meeting, the FOR decided to form a Working Group (WG) on resource adequacy for assessing RA requirement in states and for deliberating on necessary regulatory frameworks and interventions.

1.1 Working Group and Terms of Reference

The RA WG is headed by Shri. I. S. Jha, Member – CERC and consists of the following members:

1. Chairperson, Uttar Pradesh Electricity Regulatory Commission – Member
2. Chairperson, Punjab State Electricity Regulatory Commission – Member
3. Chairperson, Karnataka Electricity Regulatory Commission – Member
4. Chairperson, West Bengal Electricity Regulatory Commission – Member
5. Chairperson, Tamil Nadu Electricity Regulatory Commission – Member
6. Chairperson, Orissa Electricity Regulatory Commission – Member
7. Chairperson/Member, Uttarakhand Electricity Regulatory Commission – Member
8. Chief, (Reg. Affairs), Central Electricity Regulatory Commission – Convenor

The Terms of Reference (TOR) of the WG are as below:

1. Study to assess resource adequacy requirement in states, especially in the wake of RE expansion in the country and its impact on the existing thermal generating stations in the country.

2. Deliberate on the requirement of energy storage and suggest a regulatory framework for energy storage[1].
3. Any other matter related and incidental to the above.

United States Agency for International Development (USAID) has offered technical support to the FOR WG through its subcontractors under the South Asia Regional Energy Partnership (SAREP) Program. As a part of this technical support, Idam Infrastructure Advisory Pvt. Ltd. (Idam Infra) through its contractor Research Triangle Institute International (RTI) has supported the WG in preparing this report.

[1] The 2nd TOR item was taken up separately as part of the WG on "Regulatory Framework on Energy Storage System and Electric Vehicles", constituted during the 76th FOR meeting held on 01 October 2021. The resultant of the report was endorsed by the FOR in its 83rd meeting held on 18 November 2022 and can be found here: http://www.forumofregulators.gov.in/Data/study/FOR-Report-Framework-Energy-Storage_and_EV.pdf

2 Working Group Meetings on Resource Adequacy Framework

The WG held seven meetings from 03 April 2021 to 15 June 2023 to deliberate on the need for resource adequacy, key computational aspects, demonstrative calculations for select states, capacity sharing constructs, and monitoring and compliance mechanisms. The proceedings of these meetings are summarized below.

2.1 First Meeting on 03 April 2021

The first meeting of the working group of FOR on Resource Adequacy (RA) Framework was held virtually on 3 April 2021. The WG deliberated on the background note on Resource Adequacy presented by the Chief (RA), CERC. The WG deliberated on the importance and need of Resource Adequacy and relevant provisions to enforce standards with respect to quality, continuity, and reliability of service by distribution licensee and the role of regulators in Resource Adequacy. The second agenda of the meeting was a presentation by representative of Lawrence Berkley National Laboratory (LBNL) on "Resource Adequacy: Requirement and Framework". The presentation mainly focused on future demand-supply scenario of India in order to assess RA requirement at National and State level with an integrated planning approach and cost optimal resource mix. The third agenda of the meeting was a presentation by USAID on the report "Regulatory Framework on Resource planning". The presentation briefed about the need for resource adequacy planning, state level optimization, REPOSE tool, etc.

The WG noted that discoms' role is central to resource adequacy planning, and they may also be invited in the next WG meetings. The WG decided to have presentation on load forecasting and power procurement planning by representative of some state discoms and presentation by representative of USAID on the case study of Assam and Jharkhand in the context of DISCOM-REPOSE Tool in the next meeting.

The Minutes of the Meeting of the 1st meeting are attached as **Annexure 2**.

2.2 Second Meeting on 07 May 2021

The second meeting of the working group of FOR on Resource Adequacy Framework was held virtually on 7 May 2021. The first agenda of the meeting was to discuss a presentation by APDCL on Load Forecasting and Power Procurement Planning. The presentation briefed on the power scenario of Assam, long term PPAs contracted by APDCL, current practice of long-term power procurement, and need of REPOSE tool. The second agenda of the meeting was to discuss a presentation by USAID on Case Studies of REPOSE tool. The presentation highlighted various features of the tool, demo results (Assam and Jharkhand), live demo, etc.

The WG noted the presentations. The WG deliberated on various operational and technical aspects of the tool and emphasized on the need of revalidating accuracy of assumptions and variables considered in the tool. The WG suggested that the tool may be very useful for RE-rich states and further study needs to be done regarding scenario management, accuracy of the results, sensitivity analysis, and addition of reliability margin consideration in the tool.

The Minutes of the Meeting of the 2nd meeting are attached as **Annexure 3**.

2.3 Third Meeting on 04 April 2022

The third meeting of the working group of FOR on Resource Adequacy Framework was held virtually on 4 February 2022. The first agenda of the meeting was to discuss a presentation by WBSEDCL/WBERC on the Current Practices of Load Forecasting and Power Procurement Planning for West Bengal. The presentation highlighted a load forecasting tool developed by the State. The second agenda of the meeting was to discuss a presentation by CER-IITK on Planning for Resource Adequacy: Experience from Uttar Pradesh and Chhattisgarh. The presentation briefed about the load forecasting exercise carried out in Uttar Pradesh and Chhattisgarh.

The WG noted the presentations. The WG discussed the demand growth, demand curve, cost per unit of pumped storage, long term planning, etc. regarding the presentation by WBSEDCL. The Chief (RA), CERC suggested to the WG that an assessment be made for some sample States on resource crediting and a way forward in terms of RA framework would be suggested for consideration of the WG.

The Minutes of the Meeting of the 3rd meeting are attached as **Annexure 4**.

2.4 Fourth Meeting on 25 July 2022

The fourth meeting of the working group of FOR on Resource Adequacy Framework was held at CERC, New Delhi on 25 July 2022. The first agenda of the meeting was to discuss the Resource Adequacy Framework proposed by M/s Deloitte for the country and states with a case study of Madhya Pradesh. The second agenda of the meeting was to discuss the presentation by M/s Idam Infra on the Resource Adequacy framework outlined under the draft IEGC 2022 and the overall methodology for RA analysis for the western region and its states. The presentation highlighted the three important parameters of the RA framework viz. Planning Reserve Margin, Capacity Crediting, RA target setting philosophy, and principles for determination of these parameters with international examples.

The working group noted the presentations and suggested undertaking a similar exercise to cover all States by collecting the requisite data from the respective SLDCs with the support of FOR Secretariat. The working group suggested deliberating on the State level Demand forecasting guidelines along with the development of uniform approach/information templates for demand forecasts and the Framework for capacity trading arrangements/sharing of resources amongst states entities in the next meeting.

The Minutes of the Meeting of the 4th meeting are attached as **Annexure 5**.

2.5 Fifth Meeting on 06 January 2023

The fifth meeting of the working group of FOR on Resource Adequacy Framework was held virtually on 6 January 2023. The first agenda of the meeting was to discuss the demand forecasting mechanism envisaged under resource planning tool (REPOSE) developed by USAID which was presented by the team of USAID SAREP. The second agenda of the meeting was to discuss a presentation by M/s Idam Infra on Resource Adequacy analysis of the Western Region and the Capacity Trading framework. The presentation covered analysis using the state-level actual data acquired from the SLDCs and various capacity trading options.

The working group noted the presentations and suggested that to establish the capabilities and accuracy of the REPOSE tool, historical data need to be considered and more examples need to be demonstrated. With regards to the presentation on RA analysis, the working group suggested that Regional RA assessment should be factored in for generation planning and national-level RA should be used for operational planning. The working group also deliberated on various options presented for capacity sharing and suggested the market platform-based auction for the same. The working group decided to deliberate on the feasibility analysis of the REPOSE tool, state-level demand forecasting guidelines, and framework for capacity trading among states in the next meeting.

The Minutes of the Meeting of the 5th meeting are attached as **Annexure 6**.

2.6 Sixth Meeting on 27 May 2023

The sixth meeting of the working group of FOR on Resource Adequacy Framework was held in Varanasi on 27 May 2023. The first agenda of the meeting was to summarize the findings of the previous meetings and the second agenda was to discuss the structure of the FOR draft report of Resource Adequacy framework. Chief (RA), CERC appraised the WG on the key findings from the previous meetings. It was informed that the WG deliberated on various issues such as different methodologies of Demand Forecasting, assessment of generation resource planning with capacity credit and Planning Reserve Margin. The WG deliberated whether the RA framework should advise RA computation at the regional level or the national level. The WG also deliberated on the possibility of different mechanisms to share capacity among distribution utilities to take care of diversity of demand across the States. The presentation also covered the regional analysis consisting of RA requirement determination, allocation, and procurement.

The working group noted the presentation and suggested that the determination of RA requirement may be done at the regional level for generation resource planning. The working group deliberated on the decision of timeline for the procurement of the allocated RA requirement by the state. It was suggested that the RA procurement plan needs detailed exercise to identify the optimal and least-cost resource mix of the RA requirement allocation for meeting reliability standards and other targets such as RPO. The working group also deliberated on the determination of marginal capacity charges and performance penalties by the states or the model regulations. The working group decided to further deliberate on the Report on Resource Adequacy Framework and Draft Model Regulations in the next meeting.

The Minutes of the Meeting of the 6th meeting are attached as **Annexure 7**.

2.7 Seventh Meeting on 15 June 2023

The seventh meeting of the working group of FOR on Resource Adequacy Framework was held at CERC, New Delhi on 15 June 2023. The WG deliberated on the draft Report and discussions were held on the following key points: (a) national approach v/s. regional approach for Resource Adequacy planning, (b) Composition of resource mix for meeting RA targets, (c) determination of tenure (LT/MT/ST) of capacity contracting for RA compliance, and (d) non-compliance charge for failure to comply with RA target.

The WG noted that the national approach would be the most optimal capacity expansion strategy. The states should, however, guard against the risk of capacity shortages in case of slippages by any state. The WG finally decided to **recommend a national level RA planning approach with ongoing assessment through annual rolling plan and undertake mid-term review** for slippages, if any.

The WG further felt that the least cost procurement of resources and identification of right resource mix over longer time horizon was an involved exercise and beyond the scope of this WG. However, it was noted that the production cost modelling **to identify the optimal least-cost procurement of resources** would be the desirable approach. It was decided that determination of tenure of contracting (LT/MT/ST) and determination of non-compliance charges should be left to the states, considering state-specific situation, legacy contracts etc. With these observations, the report was unanimously endorsed by the Working Group.

The Minutes of the Meeting of the 7th meeting are attached as **Annexure 8**.

3 Resource Adequacy Overview

3.1 Background

India is aiming to install 500 GW of non-fossil fuel capacity comprising primarily of RE by 2030. It has made rapid progress toward achieving these goals. Between FY 2015 and FY 2023, the RE capacity increased three times from 40 GW to 125 GW, supplying close to 10% of the total electricity generated in FY23. As it embarks on this transition, the electricity sector faces several challenges. One of the main challenges is the treatment of RE capacity to meet peak load. Another challenge is increased system ramping and balancing needs due to increasing RE penetration. Contracting additional thermal capacity to meet peak load without considering renewables or other flexible resources could result in an oversized system and inflated costs. Additionally, systematic capacity sharing amongst states is another important requirement that would enable leveraging load and resource diversity in a nationally connected grid.

Presently, there is no specific regulations for resource planning which considers high penetration of renewable energy. Existing practice of distribution licensee for capacity addition to meet peak demand based on excel based model which has resulted in oversized system. The FOR WG is of the opinion that a more cost-effective approach to meet forecasted demand at all times with a mechanism of sharing of resource among States to maximise utilisation needs to be developed by recommending a systematic Resource Adequacy (RA) framework with a focus on ensuring reliable grid operations. Having a well-designed RA framework would be important to scale up renewables in the grid while ensuring grid reliability in a cost-effective manner.

RA entails the planning of generation and transmission resources for reliably meeting the projected demand in compliance with specified reliability standards for serving the load with optimum generation mix. This would also facilitate the scaling of RE while considering the need, inter alia, for flexible resources, storage systems for energy shift, and demand response measures for managing the intermittency and variability of renewable energy sources. RA analysis provides the tools to determine whether there are enough resources and, if not, what type of resource is needed to meet reliability needs and contract these capacities. At the same time, any surplus resulting in the analysis would facilitate the trading of the same with other constituents ensuring optimal capacity utilisation.

Well-designed system planning and RA frameworks, coordinated with state-level resource planning and procurement and supported by market mechanism, are critical to scaling renewable deployment with less curtailment and less financial and operational stress on conventional assets. System planning and RA analysis can help facilitate generation capacity sharing among states, increasing the utilization of existing generation assets.

3.2 RA Framework and Analysis

The WG deliberated on following four key aspects of Resource Adequacy Framework.

1. **Demand assessment and forecasting**

   This is the first and most critical step in which future demand requirement is assessed and forecasted considering various input parameters, policies and drivers, uncertainty analysis, and scientific forecasting methodologies.

2. **Generation resource planning**

   Once demand has been forecasted, it is important to assess existing available capacity for identifying the need for incremental capacity for meeting RA requirement. This process involves the following three sub-steps:

   a. **Capacity crediting (CC)**

      CC of a resource represents the amount of power it can provide during peak hours to ensure reliable grid operations. This is used to discount installed capacities to represent how much they will contribute towards meeting the peak and depends on the hourly demand and generation profiles.

   b. **Planning reserve margin (PRM)**

      PRM represents the percentage of resources in the system available over and above the peak demand to meet the demand reliably. It is a macro-level thumb-rule approach and involves variables such as loss of load probability (LOLP) and energy not served (ENS). If PRM is factored into planning and procurement by adding it onto the peak, it ensures sufficient resources for reliable grid operations.

   c. **RA requirement and allocation**

      Based on the forecasted demand and considering the existing available resources discounted as per their capacity credit, and factoring PRM, the next important step is to calculate the RA requirement for each demand serving entity and optimize them at the state/regional/national level and again dovetailing for its allocation down to states & demand servicing entities.

3. **Procurement planning**

   Once the RA requirement has been identified and allocated, it is important to plan out procurement of the same. This involves the following sub-steps:

   a. **Procurement resource mix**

      This step involves identification of the resource mix to meet RA requirement such that reliability standards are met and smooth RE integration is enabled while avoiding creation of stranded assets.

b. **Procurement type and tenure**

This step helps identify the first level of optimization of available capacity within the region toward meeting peak load + PRM. Then, it involves procurement of short and medium-term capacity for further optimization first within and then among regions.

c. **Capacity trading/sharing constructs**

To enable the above procurement in an optimal and cost-effective manner without leading to stranded assets, it is important to design capacity trading/sharing constructs.

4. **Monitoring and compliance**

This involves the development of an overarching framework, process flowchart and timeline, matrix for roles and responsibilities, and matrix for deliverables to ensure smooth and successful implementation of the RA framework.

To better understand the nuances of these steps and sub-steps, the WG decided to conduct a simulation of the RA framework at regional level. As an example, the Western Region (WR) was considered for analysis given its diversity in terms of hourly demand and higher RE generation profile. Computations for state-wise capacity crediting, regional RA requirement, and state-wise allocation were carried out along with assumptions for demand forecasting and planning reserve margin. Based on these simulations, the WG deliberated on an overarching RA framework including capacity trading/sharing constructs and monitoring and compliance.

This report describes each of the four steps and sub-steps in detail including its background, key questions and WG deliberations, analysis and outcomes, and recommendations.

PART A: DEMAND ASSESSMENT AND FORECASTING

4 Demand Assessment and Forecasting

The WG studied various mechanisms for demand assessment and forecasting and deliberated on key aspects of the same.

4.1 Background

Demand assessment and forecasting is the first and most crucial step of any resource adequacy and planning analysis. It involves forecasting of peak (MWs) and energy (MUs) requirement for multiple horizons (short/medium/long-term) and considers various input parameters such as historical consumption, consumer categories, weather data, econometric data, policies and drivers, etc. Long-term (LT) demand forecasting is typically undertaken to economically plan the new generating capacity and transmission networks over 10-20 years. Medium-term (MT) demand forecasting is undertaken for scheduling of fuel supplies, maintenance programs, financial planning, and tariff formulation for up to 5 years. Short-term (ST) demand forecasting is for planning start-up and shut-down schedules of generating units, reserve planning, and the study of transmission constraints over 1 day up to 1 year.

4.2 Key Questions and WG Deliberations

The WG deliberated on the following key questions pertaining to demand assessment and forecasting:

1. What is the existing demand forecasting practice?
2. What does a scientific approach entail?
3. What input parameters and policy drivers should be considered?
4. What should be the granularity and horizon?

The WG observed that at present, demand forecasting methodologies at discom- and state-level were not uniform across the country and relied on simplistic CAGR-based calculations and trend analyses. These prevailing practices are summarized in **Table 1** below:

Table 1: Prevailing Demand Forecasting Practices

State	Agency	Objective	Forecasting Horizon	timelines	Information/ data sharing responsibility	Forecasting Methodology
AP	DISCOM and STU	Tariff and transmission planning	10 years	1-year ahead	DISCOM to furnish data to STU and ERC	-
DL	DISCOM	MYT and transmission planning	5 years	31st July of the base year	DISCOM to furnish data to ERC	Must consider all consumer types, DSM, policies, net metering and economic data
GJ	DISCOMs	Transmission and power procurement planning	10 years	31st January of every year	DISCOM to furnish data to STU and SLDC	Trend analysis and reasonable assumptions for future
MP	DISCOM	MYT and transmission planning	5 years	31st March	STU to maintain database	DISCOM to adopt appropriate method
OR	STU and DISCOMs	Transmission planning	10 years	31st March	DISCOM to furnish data to STU for submitting the compiled data to ERC	Must consider past trends and economic data
PB	STU	Transmission and power procurement planning	10 years	30th Nov	DISCOM to furnish data to STU for submitting the compiled data to ERC	Month-wise peak/off-peak load considering paddy/non-paddy seasons
UP	DISCOM	MYT	5 years	1st June	DISCOM to furnish the forecasts to ERC	Must consider economic indicators of the state

The WG discussed that it is important to adopt a scientific approach at an hourly granularity that helps identify overall resource requirement to meet demand with minimal cost implications in terms of optimal capacity planning without compromising on reliability and at the same time without excess or deficit capacity. This makes the planning more realistic. It is also important to consider various demand drivers such as electric vehicles (EVs), distributed energy resources (DERs), and changes in weather conditions.

In this regard, USAID SAREP made a presentation to the WG on their demand forecasting tool, REPOSE[2]. It was presented that the tool uses scientific methods and advanced techniques to produce up to 15-year LT and 5-year MT forecasts. It has a dedicated database for historical data and factors drivers such as DERs, EVs, DSM, etc. Additionally, data on demographic variables, consumer data, weather data, and econometric variables can also be factored in. It has mathematical modelling facilities including multi-variable regression and scenario analysis, and has the ability to use multiple methods such as the traditional "partial end use" method as well as newer methods like ARIMA and ANN. It has multiple output features such as display of standard deviation, optimization, RE maximization, etc.

4.3 Analysis and Outcomes

The scientific and mathematical demand forecasting approach discussed above is a highly extensive and involved process. Hence, for illustrative purposes, the WG analysis considered the 19th EPS projections for the WR states as shown in **Figure 1** below.

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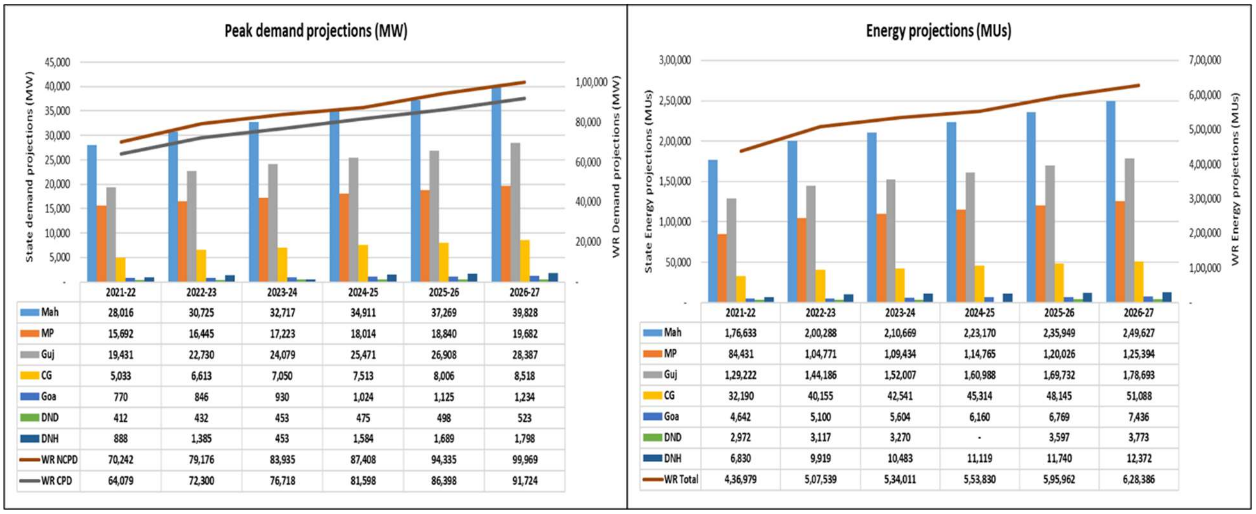
[2] USAID, https://pdf.usaid.gov/pdf_docs/PA00XGN3.pdf



Peak demand projections (MW)

	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27
Mah	28,016	30,725	32,717	34,911	37,269	39,828
MP	15,692	16,445	17,223	18,014	18,840	19,682
Guj	19,431	22,730	24,079	25,471	26,908	28,387
CG	5,033	6,613	7,050	7,513	8,006	8,518
Goa	770	846	930	1,024	1,125	1,234
DND	412	432	453	475	498	523
DNH	888	1,385	453	1,584	1,689	1,798
WR NCPD	70,242	79,176	83,935	87,408	94,335	99,969
WR CPD	64,079	72,300	76,718	81,598	86,398	91,724

Energy projections (MUs)

	2021-22	2022-23	2023-24	2024-25	2025-26	2026-27
Mah	1,76,633	2,00,288	2,10,669	2,23,170	2,35,949	2,49,627
MP	84,431	1,04,771	1,09,434	1,14,765	1,20,026	1,25,394
Guj	1,29,222	1,44,186	1,52,007	1,60,988	1,69,732	1,78,693
CG	32,190	40,155	42,541	45,314	48,145	51,088
Goa	4,642	5,100	5,604	6,160	6,769	7,436
DND	2,972	3,117	3,270	-	3,597	3,773
DNH	6,830	9,919	10,483	11,119	11,740	12,372
WR Total	4,36,979	5,07,539	5,34,011	5,53,830	5,95,962	6,28,386

Figure 1: 19th EPS Projections

CEA uses the Partial End Use Method (PEUM) for demand forecasting and has considered various consumer categories, technologies, and policies and drivers in its methodology. It has also carried out an econometric approach for forecasting. Technologies such as electric vehicles (EVs), captive power plants (CPPs), solar rooftop, and solar pumps are considered. Aggressive demand side management (DSM), energy efficiency, and conservation measures have been factored along with policy initiatives such as Power for All, Make in India, dedicated freight corridor, EVs, etc.[3]

These projections serve as the basis for subsequent computations of peak + planning reserve margin, identification of adjusted incremental capacity, allocation of RA requirement, etc.

Based on the questions raised in the above section as well as methodologies adopted by USAID SAREP and CEA, the WG deliberated on the following potential approach and recommendation for demand forecasting as shown in **Figure 2**:

Figure 2: Demand Forecasting Methodology

Additional inputs, consumption profiles of consumers, policies and drivers, and forecasting methodologies as shown in **Figure 3** may be considered:

[3] 19th EPS, CEA, 2019

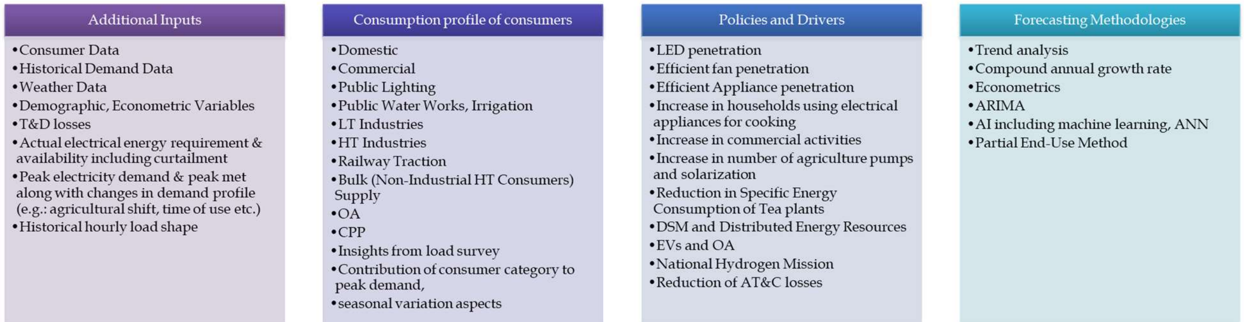


Figure 3: Demand Forecasting Inputs

4.4 Recommendations

Based on the above analysis and deliberations, the WG recommends adopting the following approach for demand forecasting:

The above-mentioned mechanisms are summarized in the table below:

Recommendations:
• Distribution licensees should undertake demand forecasting using the latest EPS as a base and consider additional inputs 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.: agricultural shift, time of use, etc.), historical hourly load shape, etc. • Distribution licensees should consider consumption profiles for each class of consumers, such as domestic, commercial, public lighting, public water works, irrigation, LT industries, HT industries, railway traction, bulk (non-industrial HT consumers), open access, captive power plants, insights from load survey, contribution of consumer category to peak demand, seasonal variation aspects, etc. • Distribution licensees should factor in various policies and drivers, such as LED penetration, efficient fan penetration, appliance penetration, increased usage of electrical appliances for cooking, etc., in households, increase in commercial activities, increase in number of agricultural pumps and solarization, changes in specific energy consumption, consumption pattern from seasonal consumers such as tea plants, DSM and DERs, EVs and OA, National Hydrogen Mission, reduction of AT&C losses, etc. • Distribution licensees should undertake this exercise to produce hourly forecasts for a rolling 1-year (ST) and 5-year (MT) horizon. • STU/SLDC should aggregate demand forecasts by distribution licensees and submit 1-year (ST) and 5-year (MT) hourly demand forecasts to CEA/NLDC. • SERC to review and approve both distribution licensee- and state-level demand forecasts.

PART B: GENERATION RESOURCE PLANNING

5 Capacity Crediting

5.1 Background

Generation planning is set to become more complex as larger amounts of variable renewable energy (vRE) generation is added to the system which is dependent on the weather. It is important to determine the contribution of these vREs (such as wind and solar) along with energy-limited resources (such as hydro and storage) towards the resource adequacy requirements. The Capacity Credit (CC) of a generating technology represents the amount of power it can reliably provide.[4] The capacity credit is measured either in terms of physical capacity (kW, MW, or GW) or the fraction of its nameplate capacity (%).

Capacity crediting ensures that the generation resources are available for meeting the demand at any point in time even with generation outages and variability in generation. It also helps in displacing the need to build new resources and encourages to use existing resources optimally. The CC of energy resources is particularly important in long-term utility planning. It can be one of the key assumptions affecting resource selection in the capacity expansion models frequently used in integrated resource planning. [5]

5.2 Key Questions and WG Deliberations

The WG deliberated upon the following key questions regarding capacity crediting:

1. What methodology should be adopted for CC computations?
2. How should CC for imports be specified?
3. How should CC for existing and new resources be calculated?

The WG discussed the following methodologies for CC computations:

1. **CC approximation with Top Demand Hours**
   In this method, the CC is approximated by averaging the historical contribution of a generator/ generator class during peak demand hours. The selection of how many peak demand hours to include, however, often varies across geographies.
2. **CC approximation with Top Net Load Hours**
   In this method, it is considered that the system is under stress when high demand coincides with low renewable energy generation. 'Net load' is defined as 'total renewable energy

[4] Draft Guidelines for Resource Adequacy Planning Framework for India, CEA, September 2022.
[5] Drivers of the Resource Adequacy Contribution of Solar and Storage for Florida Municipal Utilities, LBNL, 2019 10 24.

generation subtracted from overall demand', which must be met from dispatchable resources like thermal plants, hydro plants, etc. Due to system stress caused by the duck curve, the net load is a better proxy for system stress for new capacities than peak demand. The capacity credit can be obtained by averaging the contribution of a generator/generator class during top net load hours. Similar to the previous method, the selection of a number of top net load hours varies across geographies.

3. **Expected Load Carrying Capability (ELCC)**
   In this method, a model uses hourly time-series demand data for a particular period. The model also uses the availability of different generation resources at each hour of the year. Random outages of generators are also applied considering the historical and expected outage conditions. To calculate CC, the model first removes a generator from the system and calculates the system LOLP. The model then adds the generator back to the system and repeats the LOLP calculation. The additional generator increases system-wide firm capacity and resource adequacy, so it can accommodate more load at the previous LOLP. The additional load that can be accommodated represents the generator's ELCC.

The WG felt it important to deliberate upon the treatment of imports as resources in different states may have different hourly generation profiles which may lead to different CC values. However, it was observed that since the resource mix of imports was unknown, it would be difficult to determine its specific CC.

Further, the WG discussed how existing and new resources should be treated, as changing installed capacities or generation profiles can lead to changing CC values. To address this concern, the WG considered using an average CC value of the recent 5 years, as this would factor changing in load shape, weather patterns, generation profiles etc.

5.3 Analysis and Outcomes

This section describes the methodology and calculations conducted to arrive at CC for solar and wind across WR states.

5.3.1 Methodology

In this study, the Top Net Load Hours methodology was used to compute CC for solar and wind resources for each state from FY18 to FY22. The final CC is the average of the 5-year historical CC. Following is the methodology used:

1. For each year, the load is arranged in descending order.
2. For each hour, the net load is calculated by subtracting the solar or wind generation corresponding to that load and then arranged in descending order similar to Step 1.
3. The difference between these two load duration curves represents the contribution of solar and wind generation.

4. Installed capacity is summed up corresponding to the top 250 hours.
5. Total solar or wind generation is summed up corresponding to the top 250 hours.
6. Resultant CC is (Total Generation)/(Installed Capacity) for the top 250 hours.

$$\text{CC factor} = \frac{\text{Total Generation for top } x \text{ hours}}{\text{Total Capacity for top } x \text{ hours}}$$

This process is done for each year and the resultant CC is the average of CC values of recent 5 years.

The overall process for CC computations is shown in **Figure 4** below**Error! Reference source not found.**:

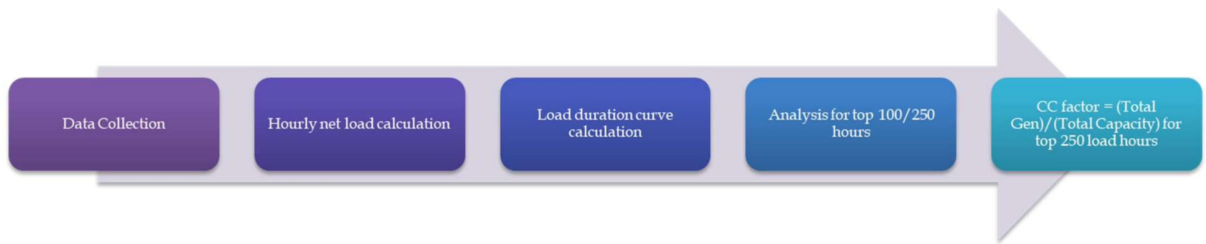


Figure 4: CC Process

5.3.2 Data Requirement and Process

The previous 5 years data pertaining to hourly load profile, hourly solar wind generation profile along with their installed capacity was collected from SLDCs of Maharashtra, Gujarat, MP, Chhattisgarh, Goa, DNH, and DD.

Table 2 shows the availability of data as requested from the SLDCs and adjustments made in case of missing data. For example, Maharashtra's solar and wind installed capacity data for FY18-FY20 was not received from the state; therefore, values from the MNRE Annual report were used. In the case of Goa, data received did not consist of hourly solar generation but annual aggregate values; therefore, Maharashtra's solar profile was applied to the annual values to create the hourly profile. Such caveats and adjustments are summarized in **Table 2**.

Table 2: Data Collection for CC

	Hourly Load	Solar IC	Hourly Solar Gen	Wind IC	Hourly Wind Gen	Adjustments
Maha	Y	(2020 to 2022)	Y	(2020 to 2022)	Y	• Solar and wind IC for 2017-20 taken from MNRE Annual Report
Guj	Y	Y	Y	Y	Y	
MP	Y	Y	Y	Y	Y	
CH	Y	Y	Y	N/A	N/A	
Goa	(CEA)	(Incremental)	(Annual)	N/A	N/A	• Solar and wind IC for 2017-18 taken from MNRE and then extended with provided annual incremental capacity as provided. • Maha gen shape applied to provided annual gen value • Load data from CEA
DND	(CEA)	(MNRE)	(Maha Shape)	N/A	N/A	• Solar IC for 2017-21 taken from MNRE Annual Report • Maha gen shape applied to gen values taken • Load data from CEA
DNH	Y	Y	(Annual)	N/A	N/A	• Solar gen annual values provided • Maha gen shape applied to annual gen values

Figure 5 below shows the monthly average hourly load curves of the WR from FY18 to FY22. The load was significantly lower for FY20-21, with a minimum load of 34,860 MW as compared to 41,033 MW for FY21-22, due to the Covid-19 pandemic.

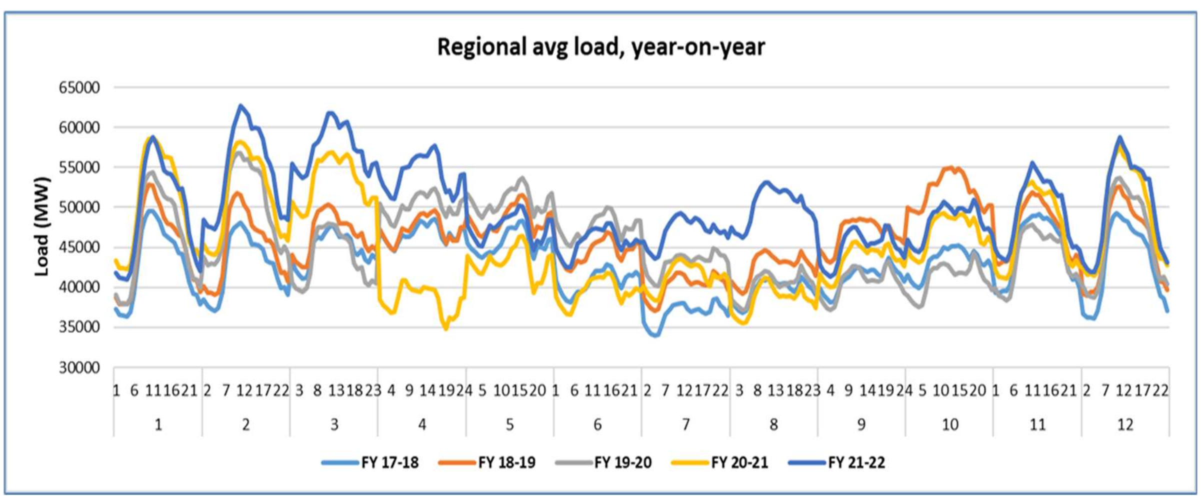


Figure 5: Average of Regional Load (actual)

State-wise graphs for Maharashtra, MP, and Gujarat can be found in **Section 15.12.1**.

Figure 6 shows the trend of solar and wind capacity addition for the WR:

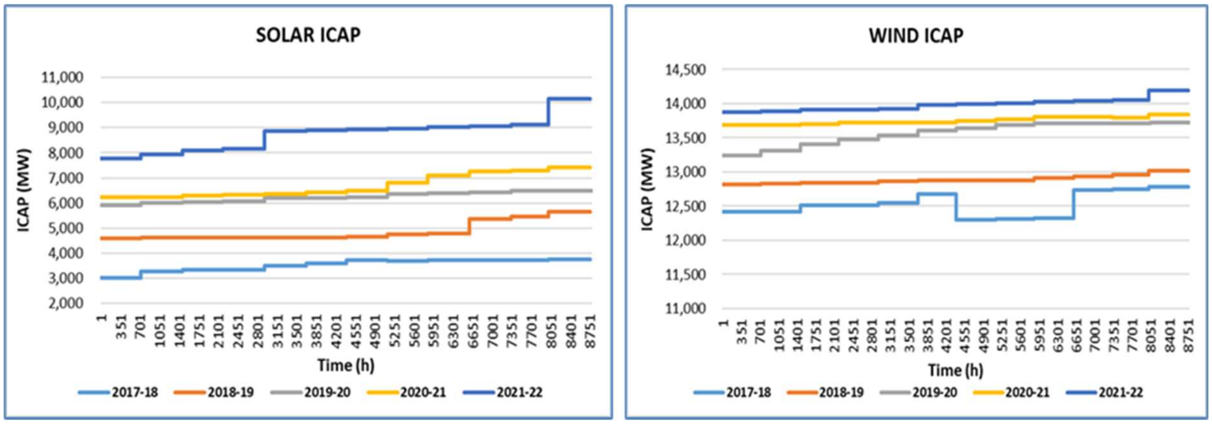


Figure 6: Solar and Wind Installed Capacity

State-wise graphs for Maharashtra, MP, and Gujarat can be found in **Section 15.12.2**.

Installations have been increasing year-on-year except for FY20-21 due to the Covid-19 pandemic. The installed capacity of solar in the WR is 10,159 MW and wind is 14,190 MW for FY22.

Figure 7 shows the solar and wind generation profile for the WR. The maximum solar and wind generation in FY21-22 was 5,754 MWh and 9,869 MWh respectively.

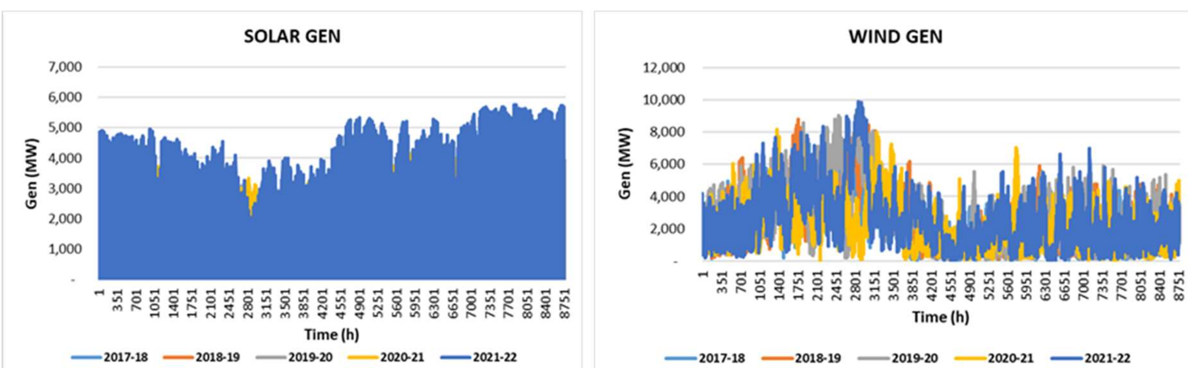


Figure 7: Solar and Wind Generation for WR

State-wise graphs for Maharashtra, MP, and Gujarat can be found in **Section 15.12.3**.

5.3.3 LDC and Net LDC

Using the above data and steps discussed in **Section 5.3.1**, the LDC and Net LDC curves were plotted for the top 250 hours of FY21-22 for solar, wind, and vRE in the WR, as shown in the **Figure 8** below. The gap between LDC and Net LDC represents the contribution of that resource.

It shows that solar contributes more towards load than wind does, as the gap between LDC and Net LDC is higher with solar than with wind.

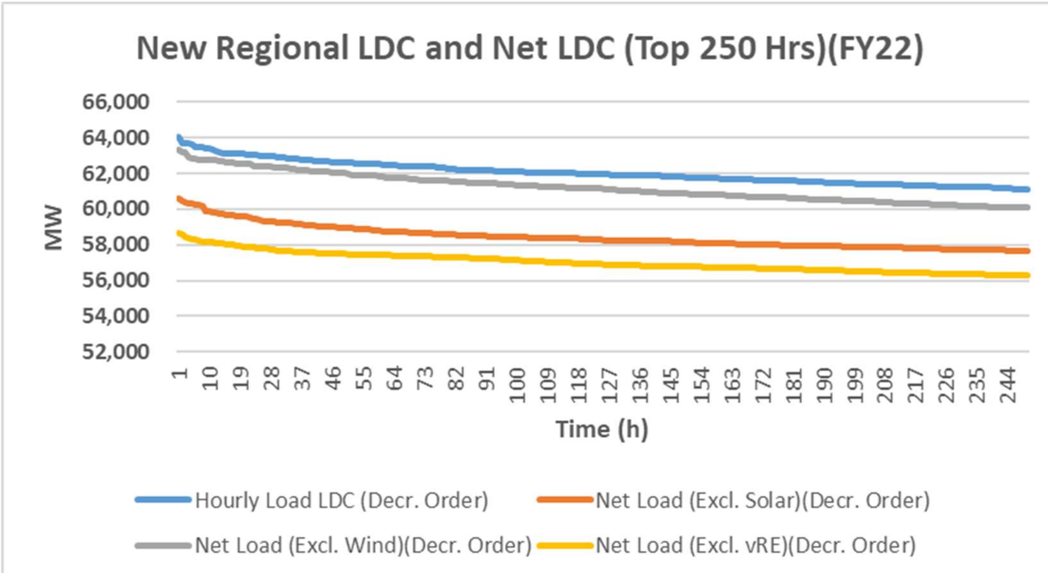


Figure 8: LDC and Net LDC for WR

5.3.4 CC Calculations and Results

As discussed in the above sections, once data is collected and LDC and Net LDC are computed, CC for each resource for the year is calculated as per the following formula:

$$\text{CC factor} = \frac{\text{Total Generation for top } x \text{ hours}}{\text{Total Capacity for top } x \text{ hours}}$$

This results in a CC of 46% for solar, 7% for wind, and 23% for vRE for the WR as a whole for FY27. These results are shown in **Table 3** below:

Table 3: CC Results for the WR

2021-22	IC based Gen for top 250 Hrs (MWh) (A)	Generation during top 250 Net Load Hours (MWh) (B)	CC (%) (C) C = B/A
Solar	25,39,662	11,65,539	46 %
Wind	35,47,596	2,53,595	7 %
Total vRE	60,87,258	14,19,134	23 %

The YoY CC values for the western region are shown in **Figure 9** below.

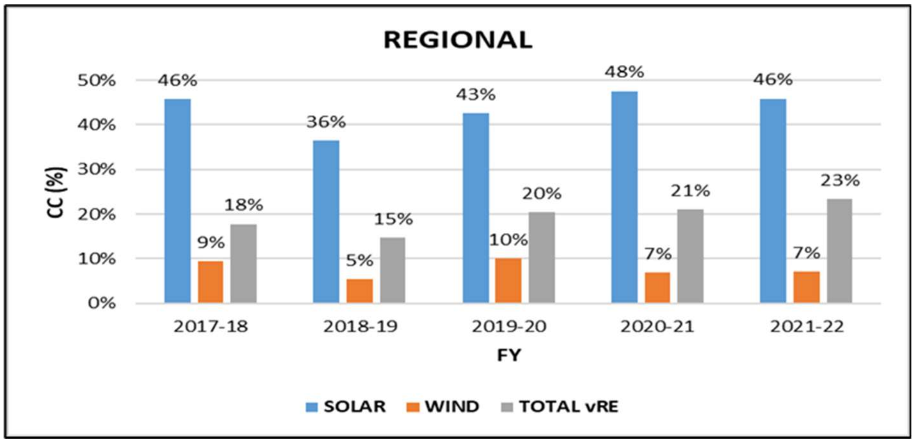


Figure 9: 5-yr Historical CC Values for WR

5-year average CC is 44% for solar, 8% for wind, and 19% for vRE. This 5-year average CC has been used as base reference for subsequent computations of RA requirement and allocation. State-specific CC results are shown in **Section 15.12.4**.

With regards to CC for non-solar/wind resources, the WG discussed that CC for hydro power resources should have two different factors based on water availability, i.e., for run-of-the-river hydro power projects and for dam-based/storage-based hydro power projects, while CC for thermal should be calculated based on coal availability and planned outage rates.

5.4 Recommendations

Based on illustrative CC computations and deliberations, the WG recommends the following:

Recommendations:
• Capacity credit of all types of generation resources is an important step for RA assessment. • For the estimation of capacity credit for vRE generation, a net load-based approach should be adopted and CC should be computed as the average of CC factors over the last 5 years on a rolling basis. • This average CC of the recent 5 years factor should be used as base reference for RA allocation and procurement for the next 5 years. • The CC calculation should consider contributions of inter-state and intra-state RE generators contracted by the distribution licensees. • There need not be a separate methodology for imports or existing/new resources. • CC for hydro resources should be computed based on water availability. CC factors for run-of-the-river hydro power projects should be different from those of dam-based/storage-based hydro power projects, with due consideration of the design and operational experience of such projects. CC for thermal resources should be computed based on coal availability and planned outages.

- The distribution licensees should calculate the CC for various resources (existing and planned) and use it in their assessment of supply availability.
- The capacity planning by distribution licensees should factor in CC while developing their procurement and RA compliance plans.
- SLDC should calculate state-specific CC factor and submit it to CEA/NLDC for regional RA requirement and allocation.

6 Planning Reserve Margin

6.1 Background

Planning Reserve Margin (PRM) is a certain percentage of the projected capacity resources available in the system over the projected peak load forecast of the system and is used to ensure the resource adequacy of the system. It is the amount of resource capacity required to meet the reliability targets such as loss of load probability (LOLP) and Normalised Energy Not Served (NENS) while making sure peak demand is met all time. It is a predominant matrix used to ensure adequacy in the power system.

In the U.S., the North American Electric Reliability Corporation (NERC) has set a reliability standard of 1-day outage in 10 years and has established PRM targets (~15%). Accordingly, regional operators (ISO) determine the planned and operational reserve margin for their jurisdictions. PRM shall ensure the availability of capacity to always meet forecasted demand. It will not only cover forecasted demand but also unexpected occurrences of outages, extreme weather events, and forecast errors. The determination of PRM should factor in the available and contracted capacity of existing and planned generation resources. The PRM seeks to ensure system reliability to meet the target reliability indices.

6.2 Key Questions and WG Deliberations

The WG deliberated on the following key questions pertaining to PRM:

1. What are the important parameters or indicators of PRM?
2. Is it to be calculated at national- or state-level?

The WG discussed that Loss of Load Probability (LOLP) and Energy Not Served (ENS) are key factors that go into the determination of PRM. CEA's Draft Resource Adequacy Guidelines define LOLP as the *"measure of the probability that a system's load will exceed the generation and firm power contracts available to meet that load in a year. E.g., 0.0274% probability of load being lost"*. The Guidelines define ENS as the *"expected amount of load (MWh) that may not be served for each year within the planning period. It is a summation of the expected number of megawatt hours of demand that may not be served for the year because of demand exceeding the available* *capacity…the metric can be normalized (i.e., divided by total system load) to create a Normalized Energy Not Served (NENS)".*

The WG discussed that the PRM shall consider the load generation profile and ensure that LOLP and ENS parameters are met. It was also noted that while formulating the National Electricity Plan 2023, LOLP of 0.2% and NENS of 0.05% have been adopted for the country by CEA.

6.3 Analysis and Outcomes

The process of computing PRM is very extensive and involved. Hence, for the purposes of illustrations, a PRM of 10% for FY 2026-27 was assumed in this demonstration with a decrement of 1% for preceding years. It was important to account for the PRM due to the following reasons:

1. It ensures that enough capacity is available to meet the forecasted peak demand.
2. It identifies whether planning is in line with demand growth.
3. It covers demand forecast errors and unexpected occurrences.
4. It ensures system reliability.

6.4 Recommendation

Based on deliberations, the WG recommends the following for PRM considerations:

Recommendations:
• **Planning Reserve Margin** (as a percentage of peak load) based on the **reliability indices** in terms of **LOLP (say, 0.2%)** and **NENS (say, 0.05%)** as may be **notified by Central Electricity Authority** should be considered by utilities in their resource adequacy and capacity planning. • The capacity planning by **utilities should factor in PRM** while developing state-level **Integrated Resource Plan**.

7 Resource Adequacy Requirement and Allocation

7.1 Background

Resource Adequacy requirement involves the identification of capacity required to reliably meet demand plus PRM, considering available capacity adjusted for capacity crediting. Once RA requirement for regional & national level is computed, it is important to allocate it further to states. This can be done based on the contribution of states towards the national/regional demand plus PRM. This process ensures appropriate and optimal requirement and allocation of resources.

Resource planning is to be optimized at the regional/national level as against the existing practice of resource planning at the state level. Regional-level optimized resource planning can be targeted initially, and national-level optimization can be targeted during the short-term operational phase through reserve optimization. Allocation of RA requirements at state level within the region can be undertaken by RLDC/NLDC/CEA based on their contribution to co-incident peak (regional/national) as part of long-term and short-term resource adequacy plan assessment.

7.2 Key Questions and WG Deliberations

The WG deliberated upon the following questions regarding the computations for RA requirement and allocation:

1. Should RA be computed at state/regional/national level?
2. What are the benefits of regional/national RA computation?
3. How should the RA requirement at the regional/national level be allocated back to states?

The WG discussed adopting regional/national approach, i.e., regional/national peak with PRM. Due to different load patterns, installed capacities, and generation profiles, it can so happen that one state within a region is in surplus while another state is in deficit. A regional/national analysis will optimize around this diversity and minimise need for additional capacity.

It was noted that while regional RA assessment has benefits over state-level assessment, a national framework would further optimize incremental capacity requirement. It was agreed that national approach would be the most optimal capacity expansion strategy. The states should, however, guard against the risk of capacity shortages in case of slippages by any state.

7.3 Analysis and Outcomes

For purposes of illustrations, the analysis involved computations of RA requirement at state and regional level, to demonstrate benefits of a regional assessment, as per the following formulations:

1. State Peak with PRM: RA Requirement = State Peak (1 + PRM)
2. Regional Peak with PRM: RA Requirement = Coincident Peak Demand (1 + PRM)

7.3.1 Capacity Surplus/Deficit Determination

The first step under RA requirement computations is to calculate the amount of capacity the WR will be in surplus/deficit in the long term. The regional peak of 91,724 MWs with 10% PRM gives an RA requirement of 1,00,896 MWs. The adjusted available capacity is 75,826 MWs, and this leads to an incremental adjusted capacity requirement of 25,070 MWs. Actual requirement of capacity to be procured will be higher than 25,070 MWs and will depend on the resource mix identified and the capacity credit (CC) of such resources. **Figure 10** shows this calculation for every year for the WR while **Figure 11** shows the incremental requirement of adjusted capacity and average hourly max load for each month of FY27.

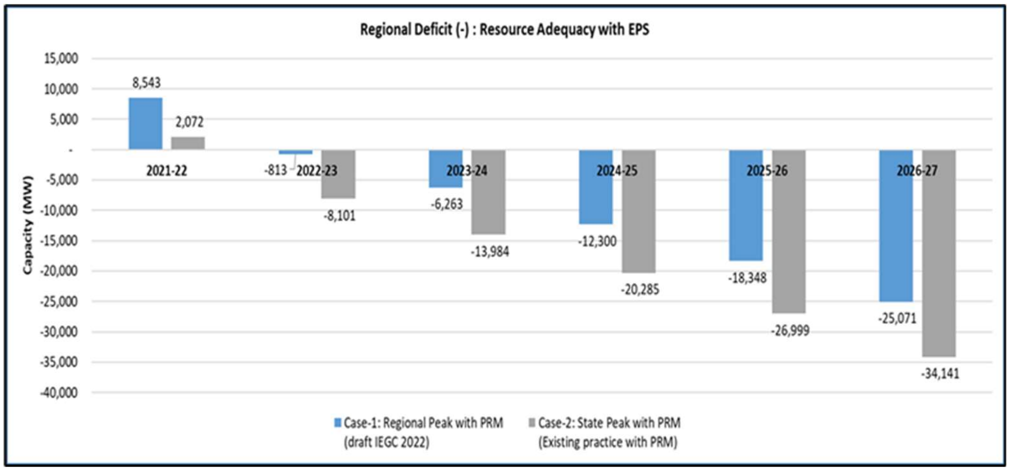


Figure 10:Capacity Surplus/Deficit

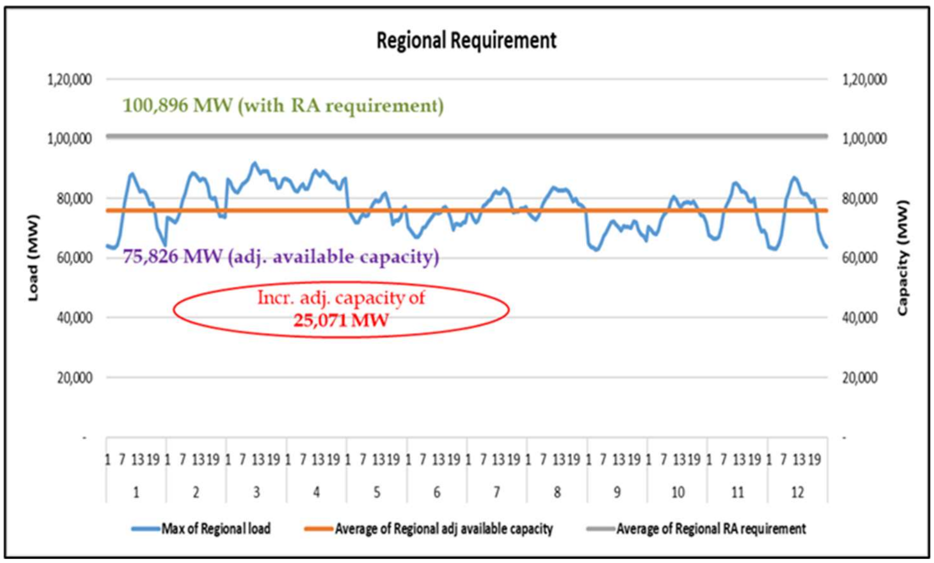


Figure 11: RA Requirement for WR

It was observed that a) only state peak demand with PRM-based approach results in an RA requirement of 34.1 GW for the WR while regional peak with PRM approach results in an RA requirement of 25.1 GWs for the WR. This reduces the need for incremental capacity addition by factoring benefits of regional diversity. This also reduces the risk of stranded assets.

State-wise surplus/deficit workings are shown in **Section 15.12.5**.

7.3.2 Incremental Capacity Allocation

Once RA requirement has been identified at the regional level using regional peak with PRM, it is important to appropriately allocate it down to states. This can be done based on:

1. State's share in the regional peak: allocation of the regional RA requirement based on the percentage share of the state in the regional peak.

2. State's share in the average of the regional and the state peak: allocation of the regional RA requirement based on the percentage share of the state in average of regional and state peak.

Figure 12 shows the incremental capacity allocation of FY27 based on the regional peak with PRM.

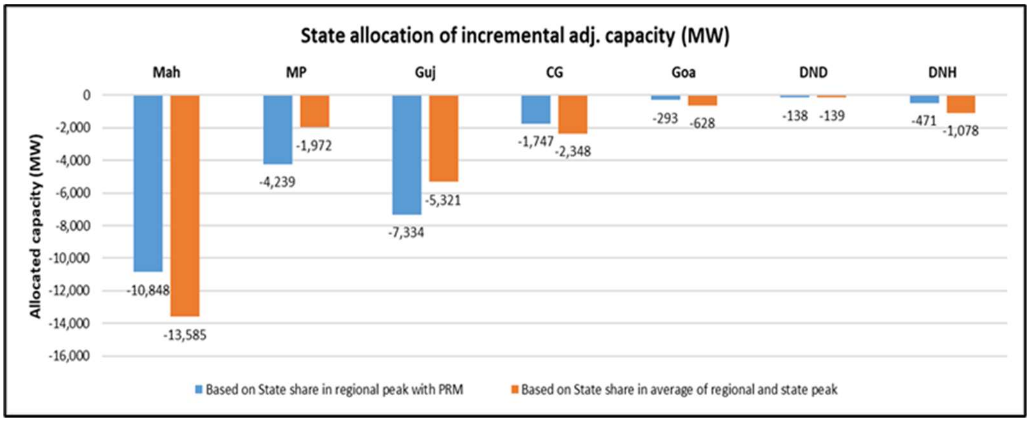


Figure 12: Allocation of Incremental Adjusted Capacity

State-wise RA requirement and allocation is shown in **Section 15.12.6**.

The following points summarize the above RA analysis:

1. Existing power procurement planning does not consider PRM while this study determines RA requirement w.r.t PRM (10% for FY27) to maintain reliability.

2. Only state peak demand with PRM-based approach is not adequate to meet reliability standards requirement.

3. Regional analysis reduces the need for incremental capacity addition and promotes sharing of resources within the region thus reducing stranded capacity.

4. The study suggests that the WR will be in capacity deficit for 31% hours while in capacity surplus for 69% hours in FY 2026-27.

5. Allocation of regional RA requirement has been done among the states according to their share in regional peak and their share in average coincident peak.

7.4 Recommendations

Based on the above calculations and deliberations, FOR recommends the following for RA requirement and allocation calculations:

Recommendations:
• **A national level RA planning approach is recommended with ongoing assessment through annual rolling plan and mid-term review** to take care of slippages, if any. • The RA requirement allocation to states/distribution licensees should be done by CEA/NLDC based on contribution to national CPD (regional level) for MT-RA and ST-RA. • Distribution licensees/SLDC should perform MT and ST RA exercise which should be reviewed and approved by SERC.

PART C: PROCUREMENT PLANNING

8 Procurement Resource Mix

8.1 Background

Once the RA requirement has been identified and allocated, it is important to compute the optimal generation capacity resource mix that can fulfill the requirements in a least-cost manner while maintaining reliability standards. The resource mix should also be such that it enables smooth RE integration and can contribute towards RPO and other targets.

8.2 Key Questions and WG Deliberations

The WG discussed the following key questions concerning determination of procurement resource mix:

1. What is the importance of and need for determination of resource mix of procurement?
2. What methodology should be adopted for the same?

The WG discussed that determining the optimal generation capacity resource mix of RA requirement and allocation can ensure maximum and smooth RE integration while avoiding creation of stranded assets. It was discussed that procurement should preferably be done in a scientific and mathematical manner by conducting a least-cost optimization study, as described in the next section.

8.3 Analysis and Outcomes

Least-cost optimization is a highly extensive and involved process. Hence, for the purposes of illustration, this exercise was not undertaken as part of analysis. However, the need was felt to deliberate on its process and benefits at a conceptual level.

Energy modelling involves system representation through input parameters such as demand forecasts and hourly profiles, technical and financial characteristics of all generators in the system, information on retiring and contracted capacity, fuel costs, economic assumptions, transmission links, constraints, etc. Capacity expansion is then carried out for the necessary time horizon which results in economic retirements and additions of power plants for meeting demand requirement. Typically, this is followed by a granular dispatch of the new resource mix to get insights on hourly load-generation balance, performance of certain technologies such as storage, reliability standards, unserved energy, dump energy, and cost of generation as well as total system cost. At the base of this setup is a mathematical model that conducts iterations and uncertainty analysis to arrive at the optimal solution.

The National Electricity Plan, 2023 (NEP)[6] has undertaken generation resource planning by considering technical and financial characteristics of various types of resources such as coal, gas, nuclear, hydro, wind, biomass, solar, BESS, PSH etc. and by using ORDENA and PLEXOS software tools. It describes the following to be key aspects of generation resource planning:

1. Achieving objectives of all Government policies
2. Achieving sustainable development
3. Fulfilling desired operational characteristics of the system such as reliability and flexibility
4. Ensuring most efficient use of resources
5. Factoring fuel availability

Key inputs to the model are peak and energy requirement projections and hourly profile, technical and financial characteristics of existing and contracted resources, hourly generation profile for solar and wind, reliability standards and targets, RPO and other constraints, transmission links and flow capacities etc.

The WG deliberated that once RA requirement has been identified at national level and allocated down to states, a least-cost capacity expansion and dispatch study will help identify optimal and least-cost resource mix for that allocation such that reliability standards are met.

8.4 Recommendations

Based on the analysis and deliberations, the WG recommends the following re. procurement resource mix:

Recommendations:

- The optimal procurement generation resource mix shall enable smooth RE integration while meeting reliability standards.
- For identification of the optimal generation procurement resource mix, optimization techniques and least-cost modelling would be desirable in order to avoid stranding of assets.
- Procurement by distribution licensees shall be consistent with the resource mix identified.

[6] National Electricity Plan, 2023, CEA

9 Procurement Type and Tenure

9.1 Background

Once the optimal resource mix for meeting RA requirement allocation has been computed, it is important to define the timeline of capacity procurement (MT/ST) and determine capacity quantum across the planning horizon. The utilities must plan how much capacity they need to procure/contract in what timeframe (MT/ST) to comply with the resource adequacy requirement. Information regarding the capacity surplus/deficit is required for deciding the amount of capacity the states are supposed to procure either bilaterally (MT) through a competitive bidding process or short-term capacity trading/sharing.

9.2 Key Questions and WG Deliberations

The WG discussed on the following aspects relating type and tenure of procurement:

1. How should the RA requirement and state-wise allocation be further bifurcated into ST/MT procurement?
2. What should be the tenure of the procurement?
3. What should be the enforcement structure?

9.3 Analysis and Outcomes

Post determination of the capacity needed to fulfill the RA requirement, it is important to define the timeline of capacity procurement. The WG discussed that while it is important to define the percentage and timeline of procurement, it may be difficult to plan and operate based on availability in the short-term capacity markets. Hence, it was discussed that the decision on percentage and timeline may be left to states. The distribution companies may identify the generation resource mix and also procurement strategy in long-term, medium-term and short-term horizon and seek approval of the State Commission.

9.4 Recommendations

The WG recommends the following in order to identify procurement type and tenure for meeting RA requirement obligations:

Recommendations:
• At the initial level, available capacity within the region should be optimized. For further optimization, procurement contract should be decided first within the region subject to the least cost resource availability considering transmission constraints & cost of transmission for procurement from outside the region and then across regions if necessary.

- The distribution companies may identify the generation resource mix and also procurement strategy in long-term, medium-term and short-term horizon and seek approval of the State Commission.
- It shall be desirable that majority and adequate contracting, to the extent possible, be done for long/medium-term.

10 Capacity Trading/Sharing Constructs

10.1 Background

As demonstrated in the above sections, there is benefit to RA frameworks at the regional level by means of sharing excess capacity with those in deficit within the region. Currently, India's short-term market is purely an energy-only market. In mid- and long-term markets, investment in building capacity is recovered through fixed charges which are recoverable at the normative level of PLF with incentives for higher PLF. The buyer is bound to consume energy from the contracted capacities. However, there is a huge liability for the buyer to pay a high fixed charge over a 25-year PPA period and sometimes consume out-of-merit energy. With an increase in RE penetration, power producers have been finding it difficult to sustain stable operations due to the reduction of PLFs. There is no incentive available for them to set up new capacities and operate the existing ones. Capacity sharing would enable stakeholders to optimize costs and increase the reliability of operations.

10.2 Key Questions and WG Deliberations

The WG deliberated on the following key issues revolving around capacity trading/sharing:

1. What different constructs can be considered for the Indian context?
2. Who can be potential buyers and sellers?
3. What should be the forward commitment horizon?
4. What should be the energy terms?
5. How would scheduling rights work?
6. What would be the payment terms?

10.3 Analysis and Outcomes

10.3.1 Objectives and Guiding Principles

Key objectives of capacity trading/sharing are:

1. To provide enough flexible capacity that can act as backup for RE generation.

2. To cost-effectively bring forward the amount of capacity needed to ensure the security of electricity supply.

3. To provide a predictable revenue stream to capacity providers.

Guiding principles of capacity trading/sharing constructs are captured in **Figure 13** below:

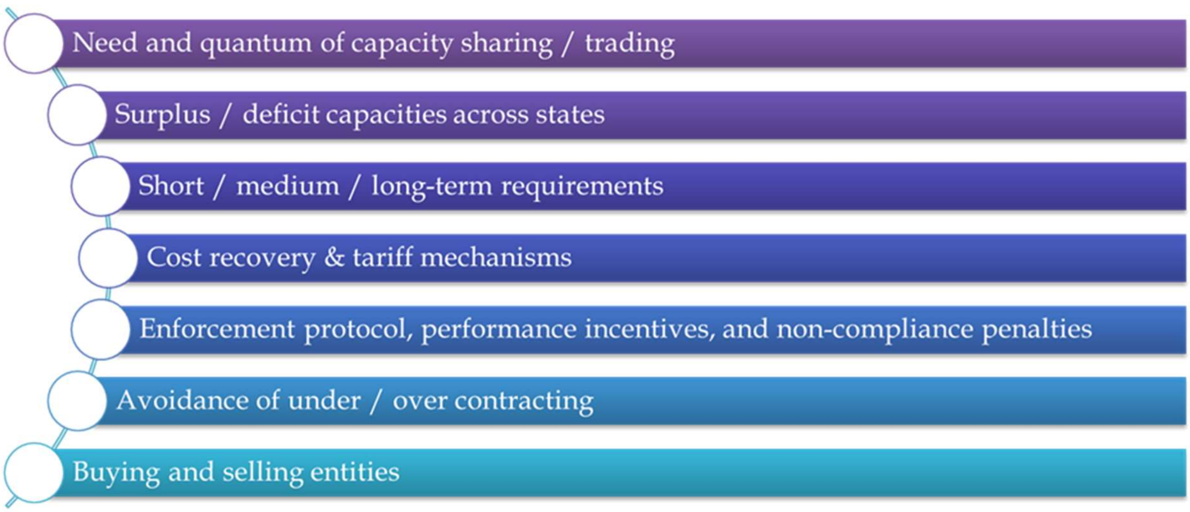


Figure 13: Guiding Principles of Capacity Trading/Sharing Constructs

1. A capacity sharing construct requires the information availability of the need and quantum of the capacity that is expected to participate as a product in the arrangement. This forms the basis of any capacity sharing mechanism.

2. The second most basic requirement for a construct is to know the state-wise capacity shortfall and surplus as that will decide who will be the buyer and seller.

3. It is also important to know the timeline of procurement of the capacity which is being shared among the utilities. The duration for which the capacity will be shared with the buyer has to be clearly defined and communicated.

4. The market participants expect cost recovery/saving by buying/selling the capacity. The cost they can recover/save in the trading arrangement must be made clear with them.

5. As in any other trading arrangement, capacity trading will also include the provision of monitoring and compliance which will make sure that non-compliance is penalized and there is some form of incentive for the stakeholders to participate in the market.

6. The main aim of a capacity sharing construct is to make sure that the available capacities are effectively and efficiently utilized so that there is no situation of over/under contracting of capacity.

7. The role of the participating utilities must be transparent as they enter into the arrangement as to whether they participate as a buyer or a seller.

Various options were deliberated upon for the application of capacity trading/sharing constructs in the Indian market. Three main options that emerged were: utility (discom)-driven bidding, market platform-based auctions, and FCR pool-based trading. Following **Table 4** summarizes the design parameters that were considered:

Table 4: Options for Capacity Trading/Sharing Constructs for Indian Market

Features	Utility (DISCOM) driven bidding	Market Platform based auction	FCR Pool based D<>D trade
Eligible technologies	• Thermal (coal & gas) • Hydro (peaking) & Storage technologies	• Thermal (coal & gas) • Hydro (peaking) & Storage technologies	• Thermal (coal & gas)
Eligible participants	• Gencos (SGS, IPP, Merchant, Captive)	• Gencos (SGS, IPP, Merchant, Captive) • DISCOMs	• DISCOMs
Forward Compliance Period	• Short (up to 1 yr.) or Medium (1 to 5 yrs.)	• Short (monthly/quarterly)	• Short or medium (weekly/ monthly/annual)
Bid Floor/ Bid Ceiling	• **total cost discovery through e-reverse auction** • Floor : guided by MVC as per State MoD • Ceiling: MVC plus INR 3.00 per unit	• Standard contract on two-part tariff basis • One sided closed auction with **bucket filling approach – pay as you bid** • Ceiling: TBD	• Alt-1: Wt. Avg. PU FC of Increment DISCOM • Alt-2: Marginal PU FC of Decrement DISCOM • No floor or ceiling price
Supplier/Buyer Bid	• Purchase or Sale bids call out as decided by (shortfall) or surplus of RA	• Discoms/Buyers to provide demand curve • Suppliers to provide quotes two part (FC+EC) for offer price & quantum	• FCR Pool Increment/Decrement to be decided based on (DCs) of all contracted generation by all participating DISCOMs
Scheduling rights	• DISCOM/Buyer gets right to schedule for entire duration of contract	• Buyer/DISCOM to have scheduling right upto DAM operation. • Successful bidder shall participate in energy market • Sharing of gains on 50:50 with buyer for MCP_DAM price > quoted EC	• Retained by resp. contracted DISCOMs except for D<>D trade for week/month on DA basis • DCs & FCR Pool Incr./Decr. to be certified by RLDC/NLDC
Features	**Utility (DISCOM) driven bidding**	**Market Platform based auction**	**FCR Pool based D<>D trade**
Trading Period	• 15-min or specified ToD slots	• Monthly/Quarterly with pre-defined Peak/Off-peak periods	• Week ahead or month ahead
Procurement	• Weekly/monthly (guided by TBCB guidelines)	• Monthly / quarterly (as per market rules)	• FCR Pool settlement on weekly/monthly/ annual basis • Energy as per ECR for scheduled energy
Performance Charge/ Bonus	• 1.5 times award price for availability shortfall	• Linked to 1.5 times prevalent market price of CC for applicable period	• No incentive/penalty
Participation	• Voluntary	• Voluntary (utilities can submit RA plan (LTDRAP) and procure on their own)	• Mandatory
Construct	• Annual auction	• Annual auction • Monthly auctions	• Timeline depends on Discom
Energy Terms	• Must supply	• Must offer in Energy Market	• Must supply
Clearing	• Auction clearing	• Market clearing on TC (FC + VC), • FC evaluated on normative availability	• Settlement

10.4 Recommendations

Based on the above analysis and deliberations, the WG recommends the following design for capacity trading/sharing constructs:

Recommendations:
• There is a need for creation of appropriate regulatory framework for short-term capacity sharing mechanism at the national level by CERC, to enable the States / distribution companies to share /exchange their short-term surplus/deficit among themselves. • The generating stations with surplus capacity may also participate in the framework.

PART D: MONITORING AND COMPLIANCE

11 Monitoring and Compliance

11.1 Background

Monitoring and compliance is necessary to ensure that resource adequacy requirements are met on a continuous basis. Currently, such standardized monitoring and compliance reporting frameworks are not in place. Draft CEA guidelines have outlined the process with timelines for the LT/ST RA plan development. IEGC (Grid Code) has stipulated certain timelines for undertaking various activities by stakeholders for the development of the RA plan. FOR Model RA Regulations would provide an overarching framework for guiding the RA process aligned with Grid Code and final RA Guidelines to be notified by CERC/CEA, respectively. Internationally, performance incentive and penalty structures differ from market to market.

11.2 Key Questions and WG Deliberations

The WG held detailed discussions around the following aspects of monitoring and compliance of the recommended RA framework:

1. What would be the roles and responsibilities of key entities?
2. What would be the process timeline and deliverable/reporting structure?
3. What would be the framework for ensuring compliance?
4. How would non-compliance be dealt with?

11.3 Analysis and Outcomes

The WG has deliberated on the key steps and timelines involved in the RA framework along with a matrix of outcomes and roles and responsibilities. This would enable a structured monitoring and compliance process for the RA framework. The process flow for the integrated RA framework is depicted in **Figure 14**:

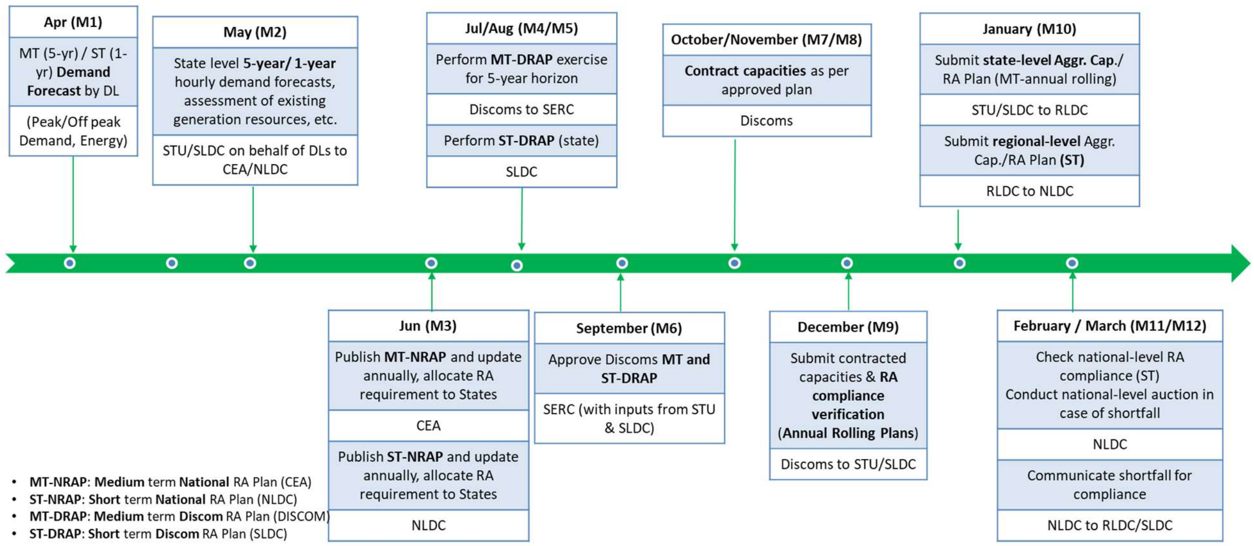


Figure 14: Process Flow for RA Framework

Discoms would conduct demand forecasting for 1- and 5-year horizons in the April of each year, to be updated annually on a rolling basis. The STU/SLDC would aggregate demand forecasts by discoms and submit a consolidated state-level 1- and 5-year forecast to CEA/NLDC by May. Based on demand forecasts, CEA would publish a medium-term national RA plan (MT-NRAP) and NLDC would publish a short-term national RA plan (ST-NRAP), allocating RA requirement to states, to be updated annually. Based on the requirement, discoms would publish the MT and ST discom RA plan (MT-DRAP, ST-DRAP) by August which would be approved by SERCs in September. October to December would be for contracting and January to March would be for approval of contracted plans and for checking compliance. The shortfall would be communicated by NLDC to RLDC/SLDC.

The following **Table 5** summarizes a matrix for the roles and responsibilities of key stakeholders in this framework:

Table 5: Roles and Responsibilities of RA Framework

	MT-NRAP	ST-NRAP	MT-DRAP	ST-DRAP
CEA	• Specify PRM, reliability indices, CC factors • Publish MT-NRAP	-	-	-
NLDC	-	• Publish ST-NRAP • Inform shortfall to RLDC/SLDC • Conduct RA auctions (ST)	-	-
RLDC	-	• Coordinate with NLDC/SLDC • Allocation of RAR to States	-	• Coordinate with NLDC/SLDC for RA • Allocation of RAR to States • Operational planning & communicate Shortfall to States
STU	• Provide State inputs to CEA/NLDC for MT-NRAP	-	• MT-DRAP Compliance verification and recommend • Prepare State level aggr. MT-DRAP • Provide State inputs to CEA	-
SLDC	-	• Coordinate & provide State inputs to RLDC/NLDC for ST-NRAP		• ST-DRAP Compliance verification • Prepare State level aggr. ST-DRAP • Coordinate & provide State inputs to RLDC/NLDC
SERC	-	-	• Approve MT-DRAP in consult with STU • Enforcement of RA compliance	• Approve ST-DRAP in consult with SLDC • Enforcement of RA compliance
DISCOMs	-	-	• MT demand forecast • Submit MT-DRAP & annual rolling plan • Contract capacity to meet RA	• ST demand forecast • Submit ST-DRAP and ST Operational plans • Contract capacity to meet RA

Key outcomes are summarized in the matrix shown in **Table 6** below:

Table 6: Key Outcomes of RA Framework

	MT-NRAP	ST-NRAP	MT-DRAP	ST-DRAP
Authority	CEA	NLDC	SLDC/STU	SLDC/STU
Horizon	5 years	1 year	5 years	1 year
Inputs	• STUs / SLDCs to provide hourly demand forecasts, generation assessments, and other details • Aggregation of DL forecasts for next 5 years	• STUs / SLDCs to provide hourly demand forecasts, generation assessments, and other details • Aggregation of DL forecasts for next 5 years	• Inputs from CEA such as PRM / indices, capacity factors, coincident peak etc. • Hourly demand forecasts by DLs.	• Inputs from CEA such as PRM / indices, capacity factors, coincident peak etc. • Hourly demand forecasts by DLs.
Outputs	1. Optimal PRM and reliability indices at all-India level conforming to LOLP and NENS targets as guidance for states 2. Optimal generation mix for the next 5 years to ensure least-cost national RA compliance as guidance for states 3. Region-wise CCs for different resource types 4. States' contribution towards national CPD	1. Demand forecasts – National/Regional 2. Resource availability as per under-construction status of new projects 3. Planned maintenance of existing schedules 4. Station-wise historic forced outage rates 5. Decommissioning plans 6. Conduct RA auctions (ST)	1. Integrated resource plan (IRP) 2. Demonstration to SERC of 100% tie-up for the first year and min. 90% tie-up for the second year to meet the requirement of their contribution towards the national CPD 3. MT/ST-contracted resources to be considered for meeting PRM, and not procurement through exchanges	1. Integrated resource plan (IRP) 2. Demonstration to SERC of 100% tie-up for the first year and min. 90% tie-up for the second year to meet the requirement of their contribution towards the national CPD 3. MT/ST-contracted resources to be considered for meeting PRM, and not procurement through exchanges
Update frequency	Annual rolling plan	Annually	Annual rolling plan	Annually
Implementation timeline	Apr to Jun (CY) (for Ensuring Financial Year: Apr to Mar)	Apr to Jun (CY) (for Ensuring Financial Year: Apr to Mar)	Jul to Sep (CY) (for Ensuring Financial Year: Apr to Mar)	Jul to Sep (CY) (for Ensuring Financial Year: Apr to Mar)
Compliance monitoring	NLDC in Jan/Feb of CY (for Ensuring Financial Year: Apr to Mar)	NLDC in Jan/Feb of CY (for Ensuring Financial Year: Apr to Mar)	STU/SERCs in Dec of CY (for Ensuring Financial Year: Apr to Mar)	SLDC/SERCs in Dec of CY (for Ensuring Financial Year: Apr to Mar)
Linkage	Will guide states for MT/ST-DRAP		Inputs taken from CEA/NLDC	

11.4 Recommendations

Based on the above analysis and discussions, the WG recommends the following for monitoring and compliance of the RA framework:

Recommendations:

- **Monitoring and Reporting**: STUs/SLDCs to communicate the **state-aggregated capacity shortfall** to the SERCs and **ask distribution licensees to commit additional capacities**.

- **Verification and Regulatory Oversight**: The **SERCs** shall provide the distribution licensees/STUs/SLDCs a **choice to comply with RA requirement** by either participating in the **national-level capacity auction** conducted by the NLDC or by way of **bilateral contracts through a competitive bidding** process.
- **Treatment for shortfall in ST-RA Compliance**: The Distribution Licensees shall comply with the RA requirement and the same to be ensured by STU/SLDCs for the State and in case of non-compliance, appropriate non-compliance charge (as determined by the State Commission) shall be applicable for the shortfall for ST RA compliance only.
- **Treatment for shortfall in MT-RA Compliance:** For MT shortfall in RA compliance, appropriate non-compliance charge (as determined by the State Commission) should be levied on the concerned distribution licensee by the concerned State Commission.

12 Summary of Recommendations

Part A: Demand Assessment and Forecasting

1. **Demand Assessment and Forecasting**
    a. Distribution licensees should undertake demand forecasting using the latest EPS as a base and consider additional inputs 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.: agricultural shift, time of use, etc.), historical hourly load shape, etc.
    b. Distribution licensees should consider consumption profiles for each class of consumers, such as domestic, commercial, public lighting, public water works, irrigation, LT industries, HT industries, railway traction, bulk (non-industrial HT consumers), open access, captive power plants, insights from load survey, contribution of consumer category to peak demand, seasonal variation aspects, etc.
    c. Distribution licensees should factor in various policies and drivers, such as LED penetration, efficient fan penetration, appliance penetration, increased usage of electrical appliances for cooking, etc., in households, increase in commercial activities, increase in number of agricultural pumps and solarization, changes in specific energy consumption, consumption pattern from seasonal consumers such as tea plants, DSM and DERs, EVs and OA, National Hydrogen Mission, reduction of AT&C losses, etc.
    d. Distribution licensees shall undertake this exercise to produce hourly forecasts for a rolling 1-year (ST) and 5-year (MT) horizon.
    e. STU/SLDC shall aggregate demand forecasts by distribution licensees and submit 1-year (ST) and 5-year (MT) hourly demand forecasts to CEA/NLDC.

Part B: Generation Resource Planning

1. **Capacity Crediting**
    a. Capacity credit of all types of generation resources is an important step for RA assessment.
    b. For the estimation of capacity credit for vRE generation, a net load-based approach should be adopted and CC shall be computed as the average of CC factors over the last 5 years on a rolling basis.
    c. This average CC of the recent 5 years factor should be used as base reference for RA allocation and procurement for the next 5 years.
    d. The CC calculation should consider contributions of inter-state and intra-state RE generators contracted by the distribution licensees.
    e. There need not be a separate methodology for imports or existing/new resources.

f. CC for hydro resources should be computed based on water availability. CC factors for run-of-the-river hydro power projects should be different from those of dam-based/storage-based hydro power projects, with due consideration of the design and operational experience of such projects. CC for thermal resources should be computed based on coal availability and planned outages.
g. The distribution licensees should calculate the CC for various resources (existing and planned) and use it in their assessment of supply availability.
h. The capacity planning by distribution licensees should factor in CC while developing their procurement and RA compliance plans.
i. SLDC should calculate state-specific CC factor and submit it to CEA/NLDC for regional RA requirement and allocation.

2. **Planning Reserve Margin**
   a. Planning Reserve Margin (as a percentage of peak load) based on the reliability indices in terms of LOLP (say, 0.2%) and NENS (say, 0.05%) as may be notified by Central Electricity Authority should be considered by utilities in their resource adequacy and capacity planning.
   b. The capacity planning by utilities should factor in PRM while developing state-level Integrated Resource Plan.

3. **Resource Adequacy Requirement and Allocation**
   a. A national level RA planning approach is recommended with ongoing assessment through annual rolling plan and mid-term review to take care of slippages, if any.
   b. The RA requirement allocation to states/distribution licensees should be done by CEA/NLDC based on contribution to national CPD (regional level) for MT-RA and ST-RA.
   c. Distribution licensees/SLDC should perform MT and ST RA exercise which should be reviewed and approved by SERC.

Part C: Procurement Planning

1. **Procurement Resource Mix**
   a. The optimal procurement generation resource mix should enable smooth RE integration while meeting reliability standards.
   b. For identification of the optimal generation procurement resource mix, optimization techniques and least-cost modelling should be desirable in order to avoid stranding of assets.
   c. Procurement by distribution licensees shall be consistent with the resource mix identified.
2. **Procurement Type and Tenure**

a. At the initial level, available capacity within the region should be optimized. For further optimization, procurement contract should be decided first within the region subject to the least cost resource availability considering transmission constraints & cost of transmission for procurement from outside the region and then across regions if necessary.
b. The distribution companies may identify the generation resource mix and also procurement strategy in long-term, medium-term and short-term horizon and seek approval of the State Commission.
c. It shall be desirable that a major portion of the capacity requirement be procured through long/medium-term contracting.

3. **Capacity Trading/Sharing Constructs**
    a. There is a need for creation of appropriate regulatory framework for short-term capacity sharing mechanism at the national level by CERC, to enable the States / distribution companies to share /exchange their short-term surplus/deficit among themselves.
    b. The generating stations with surplus capacity may also participate in the framework.

Part D: Monitoring and Compliance

1. **Monitoring and Compliance**
    a. Monitoring and Reporting: STUs/SLDCs to communicate the state-aggregated capacity shortfall to the SERCs and ask distribution licensees to commit additional capacities.
    b. Verification and Regulatory Oversight: The SERCs should provide the distribution licensees/STUs/SLDCs a choice to comply with RA requirement by either participating in the national-level capacity auction conducted by the NLDC or by way of bilateral contracts through a competitive bidding process.
    c. Treatment for shortfall in ST-RA Compliance: The Distribution Licensees should comply with the RA requirement and the same to be ensured by STU/SLDCs for the State and in case of non-compliance, appropriate non-compliance charge (as determined by the State Commission) shall be applicable for the shortfall for ST RA compliance only.
    d. Treatment for shortfall in MT-RA Compliance: For MT shortfall in RA compliance, appropriate non-compliance charge (as determined by the State Commission) should be levied on the concerned distribution licensee by the concerned State Commission.

13 Model Regulation

FOR – Working Group

Model Regulations for

Resource Adequacy Framework

(June 2023)

STATE ELECTRICITY REGULATORY COMMISSION

Model Regulations for Resource Adequacy Framework

(Draft)

No………. Date……….

NOTIFICATION

In exercise of the powers conferred under section 181 of the Electricity Act, 2003 (36 of 2003), read with section 61, 66, and 86 thereof, section 16 of the Electricity (Amendment) Rules, 2022, under section 5 of the Central Electricity Regulatory Commission (Indian Electricity Grid Code) Regulations 2023, and all other powers enabling it in this behalf, and after previous publication, the ………. State Electricity Regulatory Commission hereby makes the following Regulations, namely -

Chapter 1

Preliminary

1. Short Title, Extent, and Commencement

1.1. These Regulations may be called the ………. State Electricity Regulatory Commission (Framework for Resource Adequacy) Regulations, 202X.

1.2. These Regulations shall extend to the whole state of ……….

1.3. These Regulations shall come into force from the date of their notification in the Official Gazette.

2. Objective

2.1. The objective of these Regulations is to enable the implementation of Resource Adequacy framework by outlining a mechanism for planning of generation and transmission resources for reliably meeting the projected demand in compliance with specified reliability standards for serving the load with an optimum generation mix.

2.2. The Resource Adequacy framework shall cover a mechanism for demand assessment and forecasting, generation resource planning, procurement planning, and monitoring and compliance.

3. Scope and Applicability

3.1. These Regulations shall apply to the generating companies, distribution licensees, State Load Despatch Centre, State Transmission Utility, and other grid connected entities and stakeholders within the State of ……….

4. Definitions

4.1. In these Regulations, unless the context otherwise requires,

a. "**Act**" means the Electricity Act, 2003 (36 of 2003) and subsequent amendments thereof.

b. "**Authority**" means Central Electricity Authority referred to in sub-section (1) of Section 70 of the Act.

c. "**Capacity Credit**" or "**CC**" means a percentage of a resource's nameplate capacity that can be counted towards resource adequacy requirements.

d. "**Commission**" or "**State Commission**" means the ………. Electricity Regulatory Commission (SERC) constituted under the Act.

e. "**Expected Energy Not Served**" or "**EENS**" means the expected amount of load (MWh) that may not be served for each year within the time horizon for Resource Adequacy planning.

f. "**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.

g. "**Medium term**" means five years for development of demand forecast, generation resource plan, and procurement plan.

h. "**Medium-Term Distribution Resource Adequacy Plan**" or "**MT-DRAP**" means plan for assessment of medium-term resource adequacy by the distribution licensee.

i. "**Medium-Term National Resource Adequacy Plan**" or "**MT-NRAP**" means plan for assessment of medium-term resource adequacy at national level by Authority.

j. "**Net Load**" means the load derived upon exclusion of actual generation (MW) from renewable energy generation resources from gross load prevalent on the Grid during any time-block.

k. "**Normalized Energy Not Served**" or "**NENS**" is normalization of the EENS by dividing it by the total system load.

l. "**Planning Reserve Margin**" or "**PRM**" means a specified percentage of available capacity above peak demand as may be stipulated by Authority or Commission for the purpose of generation resource planning.

m. "**Resource Adequacy**" or "**RA**" means a mechanism to ensure adequate supply of generation to serve expected demand (including peak, off peak and in all operating conditions) reliably in compliance with specified reliability standards for serving the load with an optimum generation mix with a focus on integration of environmentally benign technologies after taking into account the need, inter alia, for flexible resources, storage systems for energy shift, and demand response measures for managing the intermittency and variability of renewable energy sources.

n. "**Short term**" means one year for development of demand forecast, generation resource plan, and procurement plan.

o. "**Short-Term Distribution Resource Adequacy Plan**" or "**ST-DRAP**" means plan for assessment of short-term resource adequacy by the distribution licensee.

p. "**Short-Term National Resource Adequacy Plan**" or "**ST-NRAP**" means plan for assessment of short-term resource adequacy by NLDC.

4.2. All other words and expressions used in these Regulations, although not specifically defined herein above, but defined in the Act, shall have the meaning assigned to them in the Act. The other words and expressions used herein but not specifically defined in these Regulations or in the Act but defined under any law passed by the Parliament applicable to the electricity industry in the State shall have the meaning assigned to them in such law.

Chapter 2

General

5. Resource Adequacy Framework

5.1. Resource Adequacy framework entails the planning of generation and transmission resources for reliably meeting the projected demand in compliance with specified reliability standards for serving the load with an optimum generation mix.

5.2. Resource Adequacy framework shall cover following important steps:

a) Demand assessment and forecasting
b) Generation resource planning
c) Procurement planning
d) Monitoring and compliance

5.3. The medium and short term for the purpose of these Regulations shall be considered as:

a) Medium term procurement plan for a period up to five years; and
b) Short-term procurement plan for a period up to one year.

5.4. The distribution licensee shall develop and prepare Medium-Term Distribution Resource Adequacy Plan (MT-DRAP) and Short-Term Distribution Resource Adequacy Plan (ST-DRAP) in accordance with the conditions outlined under these Regulations.

Chapter 3

Demand Assessment and Forecasting

6. Long-term and Medium-term Demand Forecast

6.1. Demand assessment and forecasting is an important step for Resource Adequacy assessment. It shall entail hourly or sub-hourly assessment and forecasting of demand within the distribution area of distribution licensee for multiple horizons (short/medium/long-term) using comprehensive input data and policies and drivers and scientific mathematical modelling tools.

6.2. The distribution licensee shall be responsible for the assessment and forecasting of demand (MW) and energy (MWh) within its own control area.

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 load forecast for a customer category by adopting any of the following and/or combination of following methodologies:

a) compounded average growth rate (CAGR);
b) end use or partial end use;
c) trend analysis;
d) Auto-regressive integrated moving average (ARIMA);
e) AI including machine learning, ANN techniques; and
f) econometric (specifying the parameters used, algorithm, and source of data).

6.5. The distribution licensee may use 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, business as usual, aggressive) as outlined under Clause 6.14.

6.6. 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.

6.7. The distribution licensee shall utilize state-of-the-art tools, scientific and mathematical methodologies, and comprehensive database such as but not limited to weather data, historical data, demographic and econometric data, consumption profiles, impact of policies and drivers etc. as may be applicable to their control area.

6.8. The distribution licensee may modify the load obtained on either side, for each customer category, by considering the impact for each of the but not limited to the following activities. The impact shall be considered by developing trajectories for each of the activities based on the economic parameters, policies, historical data, and projections for the future.

a) demand-side management;
b) open access;
c) distributed energy resources;
d) DSM and demand response measures;
e) electric vehicles;
f) tariff signals;
g) changes in specific energy consumption,
h) increase in commercial activities with electrification
i) increase in number of agricultural pump sets and its solarization
j) changes in consumption pattern from seasonal consumers
k) availability of supply; and
l) policy influences such as 24X7 supply to all customers, LED penetration, efficient use of fans/appliances, increased use of appliances for cooking/heating applications, electrification policies, distributive energy resources, storage, and policies, which can impact econometric parameters, impact of national hydrogen mission. For each policy, a separate trajectory should be developed for each customer category.

6.9. The distribution licensee may take into consideration any other factor not mentioned in clause 6.8 after recording the merits of its consideration.

6.10. The medium-term load profile of the customer categories for which load research has been conducted may be refined on the basis of load research analysis. A detailed explanation for refinement conducted must be provided.

6.11. The summation of energy forecast (MWh) for various consumer categories upon adjusting for captive, prosumer, and open access load forecast, as obtained as per clauses 6.4 to clause 6.10, as the case may be, shall be the load forecast for the licensee.

6.12. The licensee shall calculate the load forecasts (in MWh) by adding a loss trajectory approved by the Commission in the latest tariff order. In the absence of the loss trajectory as approved by the Commission for the planning horizon, an appropriate loss trajectory stipulated by State or National policies shall be considered with a detailed explanation.

6.13. The peak demand (in MW) shall be determined by considering the average load factor, load diversity factor, seasonal variation factors for the last three years and the load forecasts (in MWh) obtained in clause 6.12. If any other appropriate load factor is considered for future years, a detailed explanation shall be provided.

6.14. The distribution licensee shall conduct sensitivity and probability analysis to determine the most probable demand forecast. The distribution licensee must also develop long-term and medium-term demand forecasts for possible scenarios, while ensuring that at least three different scenarios (most probable, business as usual, and aggressive scenarios) are developed.

7. Short term (Hourly/Sub-hourly) Demand Forecast and Aggregation at State

7.1. The distribution licensee shall develop a methodology for hourly or sub-hourly demand forecasting and shall maintain a historical database.

7.2. For the purpose of ascertaining hourly load profile and for assessment of contribution of various customer categories to peak demand, load research analysis shall be conducted and influence of demand response, load shift measures, time of use shall be factored in by distribution licensee with inputs from state load dispatch center. A detailed explanation for refinement conducted must be provided.

7.3. The distribution licensee shall utilize state-of-the-art tools, scientific & mathematical methodologies and comprehensive data such as but not limited to weather data, historical data, demographic and econometric data, consumption profiles, policies and drivers etc. as may be applicable to their control area.

7.4. The distribution licensee shall produce hourly or sub-hourly 1-year short-term (ST) and 5-year medium-term (MT) forecasts on a rolling basis and submit to SLDC by 30th April of each year for the ensuing year(s).

7.5. STU with inputs from SLDC and based on the demand estimates of the distribution licensees of the State, shall estimate, in different time horizons, namely long-term, medium term and short term, the demand for the entire State duly considering the diversity of the State.

7.6. SLDC shall aggregate demand forecasts by distribution licensees, consider the load diversity, congruency, seasonal variation aspects and shall submit state-level aggregate demand forecasts (MW and MWh) to the Authority and NLDC and RLDC by 31st May of each year for the ensuring year(s).

Chapter 4

Generation Resource Planning

8. Generation resource assessment and planning is the second step after demand assessment and forecasting and entails assessment of the existing and contracted resources considering their capacity credit and identification of incremental capacity requirement to meet forecasted demand including planning reserve margin.

9. Key contours and important steps in Generation Resource Planning:

9.1. Generation resource planning shall entail the following steps namely, (a) capacity crediting of generation resources, (b) assessment of planning reserve margin, and (c) ascertaining resource adequacy requirement and allocation for obligated entities within control area (regional/state).

9.2. The distribution licensee shall map all its contracted existing resources, upcoming resources, and retiring resources to develop the existing resource map in MW for the long term and medium term.

9.3. The mapping shall include critical characteristics and parameters of the generating machines, such as heat rate, auxiliary consumption, ramp-up rate, ramp-down rate, etc., for thermal machines; hydrology and machine characteristics, etc., for hydro machines; and renewable resources, their Capacity factors/CUFs, etc. for renewable resource–based power plants to be considered in the resource plan. All the characteristics and parameters with their values for each generating machine considered shall be provided in the resource plan.

9.4. Constraints such as penalties for unmet demand, forced outages, spinning reserve requirements, and system emission limits as defined in State and Central electricity grid codes and emission norms specified by the Ministry of Environment and Forest shall be identified and enlisted.

9.5. The distribution licensee shall also include a planning reserve as specified by the Authority or Commission, as the case may be. In the absence of any guidelines from the Commission, the distribution licensee can consider suitable planning reserve. The value of planning reserve considered sahll be stipulated in the resource plan along with justifications.

10. Capacity Crediting of Generation Resources

10.1. The distribution licensee shall compute Capacity Credit (CC) factors for their contracted generation resources by applying the net load-based approach as outlined under Clause 10.2 of this Regulation. The five-year average of the Capacity Credit (CC) factor for each type of the contracted generation resource for the recent five years on a rolling basis shall be considered as Capacity Credit factor for the purpose of generation resource planning.

10.2. The Net Load based approach/methodology for determination of Capacity Credit (CC) factors for generation resources (including wind and solar) shall be adopted as under:

a) For each year, the hourly recorded Gross Load for 8760 hours (or time-block) shall be arranged in descending order.

b) For each hour, the Net Load is calculated by subtracting the actual wind or solar generation corresponding to that load for 8760 hours (or time-block) and then arranged in descending order similar to Step 1.

c) The difference between these two load duration curves represents the contribution of capacity factor of wind generation or solar generation, as the case may be.

d) Installed capacity of wind or solar generation capacity is summed up corresponding to the top 250 load hours.

e) Total generation from wind or solar generation corresponding to these top 250 hours is summed up.

f) Resultant CC factor is (Total Generation for top load 250 hours)/(Installed RE Capacity for top load 250 hours), as per formula below:

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

g) The process for CC factor determination shall be undertaken for each year for duration of past five-years and the resultant CC is the average of CC values of past 5 years.

10.3. For the purpose of Inter-state contracted RE generation or intra-state RE resources, contribution of CC factor for the RE or generation resource where such resource is located into grid (viz. inter-state or intra-state, as the case may be) as contracted by the distribution licensee shall be considered. For this purpose, CC factors as specified by Authority or the Commission shall be considered.

10.4. CC factors for hydro generation resources shall be computed based on water availability with different CC factors for run-of-the-river hydro power projects and dam-based/storage-based hydro power projects. CC for thermal resources shall be computed based on coal availability and forced outages.

10.5. The distribution licensee shall share CC factors for their contracted resources along with justification for its computations with State Load Despatch Centers.

10.6. SLDC shall calculate state-specific CC factors considering the aggregate State Demand and State Net Load and contracted RE generation resources available in the State and shall submit such CC factor information to the Authority and NLDC and RLDC from time to time.

11. Assessment of Planning Reserve Margin (PRM)

11.1. Planning Reserve Margin (PRM) as a percentage of peak load represents the excess generation resource or planning reserve required to be considered for the purpose of generation resource planning.

11.2. Such Planning Reserve Margin (PRM) factor (for example, 7%) shall be based on the reliability indices in terms of Loss of Load Probability (LOLP, for example, 0.2%) and Normalized Energy Not Served (NENS, for example, 0.05%) as may be specified by the Authority and the same shall be considered by utilities in their planning for resource adequacy requirement and generation resource capacity planning.

11.3. The capacity planning by the distribution licensee and State level resource adequacy planning by STU/SLDC shall factor in PRM while developing state-level Integrated Resource Plan.

12. Ascertaining Resource Adequacy Requirement and its Allocation for Control Area

12.1. Upon applying CC factors as determined under Regulation 10 of these regulations and determining adjusted capacity for contracted generation resources (existing and planned), the sum of such adjusted contracted generation capacity (existing and planned) over a time axis of 15-minute intervals or longer, but not more than one hour, shall form the resource map of the distribution licensee.

12.2. The distribution licensee shall subtract the resource map developed in clause 12.1 from the demand forecast developed in section 6 (ref. Clause 6.13) to identify the resource gap. The resource gap in terms of RA compliance for the distribution licensee for the long term and medium term shall be developed in the manner as specified in these Regulations.

12.3. The distribution licensee shall conduct sensitivity and probability analysis to determine the most probable resource gap. The distribution licensee shall also develop long-term and medium-term resource gap plans for possible scenarios, while ensuring that at least three different scenarios (most probable, business as usual, and aggressive) are developed.

12.4. Based on most probable scenario, the distribution licensee shall undertake development of Medium-term Distribution Resource Adequacy Plan (MT-DRAP) and Short-term Distribution Resource Adequacy Plan (ST-DRAP) exercise by 31st August of each year to meet RA target requirement.

12.5. RA requirement planning shall be done with reference to national coincident peak to optimize requirement of incremental capacity addition through annual rolling plan. Mid-term review of national RA requirement planning shall be conducted to check for events of slippages by states, if any.

12.6. While planning RA requirement, the distribution licensee shall duly factor in the allocation of RA requirement to the state as may be suggeste by the Authority or the NLDC, as the case may be, based on contribution to National Co-incident Peak Demand (CPD) for MT-RA and ST-RA.

12.7. The Commission shall approve MT-DRAP and ST-DRAP of the distribution licensees by 30th September of each year for the ensuring year(s) incl. annual rolling plans, as the case may be, upon taking into consideration various scenarios as well as allocation of Resource Adequacy requirement allocated to the State/distribution licensee based on its contribution to the National peak or National RA requirement as determined by Authority or the NLDC or the RLDC , as the case may be.

Chapter 5

Procurement Planning

13. Procurement planning shall consist of (a) determining the optimal power procurement resource mix, (b) deciding on the modalities of procurement type and tenure, and (c)

engaging in the capacity trading or sharing to minimize risk of resource shortfall and to maximize rewards of avoiding stranded capacity or contracted generation.

14. Procurement Resource Mix

14.1. The distribution license in its power procurement strategy shall lay emphasis on the optimal procurement generation resource mix that shall enable smooth RE integration in its portfolio of power procurement resource options while meeting reliability standards.

14.2. For identification of the optimal generation procurement resource mix, optimization techniques and least-cost modelling shall be employed in order to avoid stranding of assets. The distribution licensee shall engage in adoption of least cost modelling and optimization techniques and demonstrate the same in its overall power procurement planning exercise to be submitted to Commission for approval.

14.3. Procurement by distribution licensees shall be consistent with the identified resource mix and considering overall national electricity plan and policies notified by the Appropriate Government from time to time.

15. Procurement Type and Tenure

15.1. The distribution licensee, while determining the modalities and tenure of procurement of resource mix, shall ensure that at the initial level, available capacity within the region shall be optimized. For further optimization, procurement contract shall be decided first within the region subject to the least cost resource availability considering transmission constraints & cost of transmission for procurement from outside the region and then across regions if necessary.

15.2. The distribution licensees shall identify the generation resource mix and also procurement strategy in long-term, medium-term and short-term horizon and seek approval of the Commission.

15.3. In its overall power procurement planning approach, the distribution licensee shall lay greater emphasis on adequate contracting through long and medium term arrangements.

15.4. Assessment through Annual Rolling Plan shall ascertain incremental capacity addition requirement through MT/ST upon factoring in existing and planned procurement initiatives of the distribution licensee.

15.5. The distribution licensee shall contract capacities by 30th November of each year and submit the Annual Rolling Plan to STU/SLDC by 31st December of each year for ensuring year(s).

15.6. STU and SLDC shall submit state-level aggregated plan to RLDC and RLDC shall submit regional-level aggregated plan to NLDC by 31st January of each year for the ensuing year(s).

16. Sharing of Capacity

16.1. The distribution licensee shall duly factor in the possibility of short-term capacity sharing while preparing the Resource Adequacy plan and optimally utilize the platform for inter-state capacity sharing or trading mechanism created by the Central Commission, and optimize the capacity costs as far as possible .

16.2. The distribution licensee shall submit information about contracted capacity to the SLDC and the STU for compliance verification.

16.3. The distribution licensee, the STU and the SLDC shall seek approval of the Commission to the procurement plan as well as Annual Rolling Plans.

Chapter 6

Monitoring and Compliance

17. Monitoring and Compliance

17.1. **Monitoring and Reporting**: Based on the MT-DRAP and ST-DRAP, STU and SLDC shall communicate the state-aggregated capacity shortfall to the State Commission by 30th September of each year for the ensuring year(s) and advise the distribution licensees to commit additional capacities.

17.2. **Treatment for shortfall in RA Compliance**: Distribution licensees shall comply with the RA requirement and in case of non-compliance, appropriate non-compliance charge shall be applicable for the shortfall for RA compliance.

Chapter 7

Roles and Responsibilities and Timelines

18. Data Requirement and Sharing Protocol

18.1. Distribution licensees 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.: agricultural shift, time of use, etc.), historical hourly load shape, etc.

18.2. Distribution Licensee shall maintain all statistics and database pertaining to policies and drivers, such as LED penetration, efficient fan penetration, appliance penetration, increased usage of electrical appliances for cooking, etc., in households, increase in commercial activities for geographic areas/regions, increase in number of agricultural pumps and solarization within control area, changes in specific energy consumption, consumption pattern from seasonal consumers such as tea plants, DSM and DERs, EVs and OA, National Hydrogen Mission, reduction of AT&C losses, etc. shall also be shared.

18.3. Distribution Licensee shall maintain at least past 10 years of statistics in its database pertaining to consumption profiles for each class of consumers, such as domestic, commercial, public lighting, public water works, irrigation, LT industries, HT industries, railway traction, bulk (non-industrial HT consumers), open access, captive power plants, insights from load survey, contribution of consumer category to peak demand, seasonal variation aspects, etc. shall also be shared.

18.4. SLDC shall maintain the licensee-specific as well as aggregate for state as whole, the statistics and database pertaining to aggregate demand assessment and forecasting data mentioned above and share state-level assessment with CEA and NLDC for regional/national assessment from time to time.

18.5. The distribution licensee shall share information and data pertaining to the existing and contracted capacities with their technical and financial characteristics including hourly generation profiles to with STU/SLDC for computation of state-level capacity credit factors and for preparation of state-level assessment.

18.6. SLDC and STU shall aggregate generation data and share state-level assessment with CEA and NLDC for assessment of RA requirement.

18.7. STU shall communicate allocation of regional and national RA requirement to the distribution licensees.

19. Timelines

19.1. Distribution licensees shall submit demand forecasts to SLDC by 30th April of each year for the ensuring year(s).

19.2. SLDC shall aggregate and submit state-level forecasts to CEA and NLDC by 31st May of each year for the ensuring year(s).

19.3. Distribution licensees shall perform MT-DRAP and ST-DRAP exercise by 31st August of each year for the ensuring year(s).

19.4. STU and SLDC shall submit state-level aggregated plan to NLDC by January of each year.

Chapter 8

Miscellaneous

20. Power to Give Directions

20.1. The Commission may from time to time issue such directions and orders as considered appropriate for implementation of these regulations.

21. Power to Relax

21.1. The Commission may by general or special order, for reasons to be recorded in writing, and after giving an opportunity of hearing to the parties likely to be affected, may relax any of the provisions of these Regulations on its own motion or on an application made before it by an interested person.

22. Power to Remove Difficulties

22.1. If any difficulty arises in giving effect to the provisions of these Regulations, the Commission may, by an order, make such provisions, not inconsistent to the provision of the Act and these Regulations, as may appear to be necessary for removing the difficulty.

(Secretary)

….SERC

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15 Annexures

15.1 Annexure 1

Letter of Constitution of the Working Group

15.2 Annexure 2

Minutes of Meeting (MoM) for the 1st Meeting of the FOR Working Group

15.3 Annexure 3

Minutes of Meeting (MoM) for the 2nd Meeting of the FOR Working Group

15.4 Annexure 4

Minutes of Meeting (MoM) for the 3rd Meeting of the FOR Working Group

15.5 Annexure 5

Minutes of Meeting (MoM) for the 4th Meeting of the FOR Working Group

15.6 Annexure 6

Minutes of Meeting (MoM) for the 5th Meeting of the FOR Working Group

15.7 Annexure 7

Minutes of Meeting (MoM) for the 6th Meeting of the FOR Working Group

15.8 Annexure 8

Minutes of Meeting (MoM) for the 7th Meeting of the FOR Working Group

15.9 Annexure 9

This section includes slides from the Presentation for the 4th Meeting of the FOR Working Group on "Resource Adequacy and Regulatory Framework"

15.10 Annexure 10

This section includes slides from the Presentation for the 5th Meeting of the FOR Working Group on "Resource Adequacy and Regulatory Framework"

15.11 Annexure 11

This section includes slides from the Presentation for the 6th Meeting of the FOR Working Group on "Resource Adequacy and Regulatory Framework"

15.12 Annexure 12

This section includes results for state-specific RA computations for the states of Maharashtra, MP, and Gujarat.

15.12.1 Monthly Avg. Hourly Load Curves

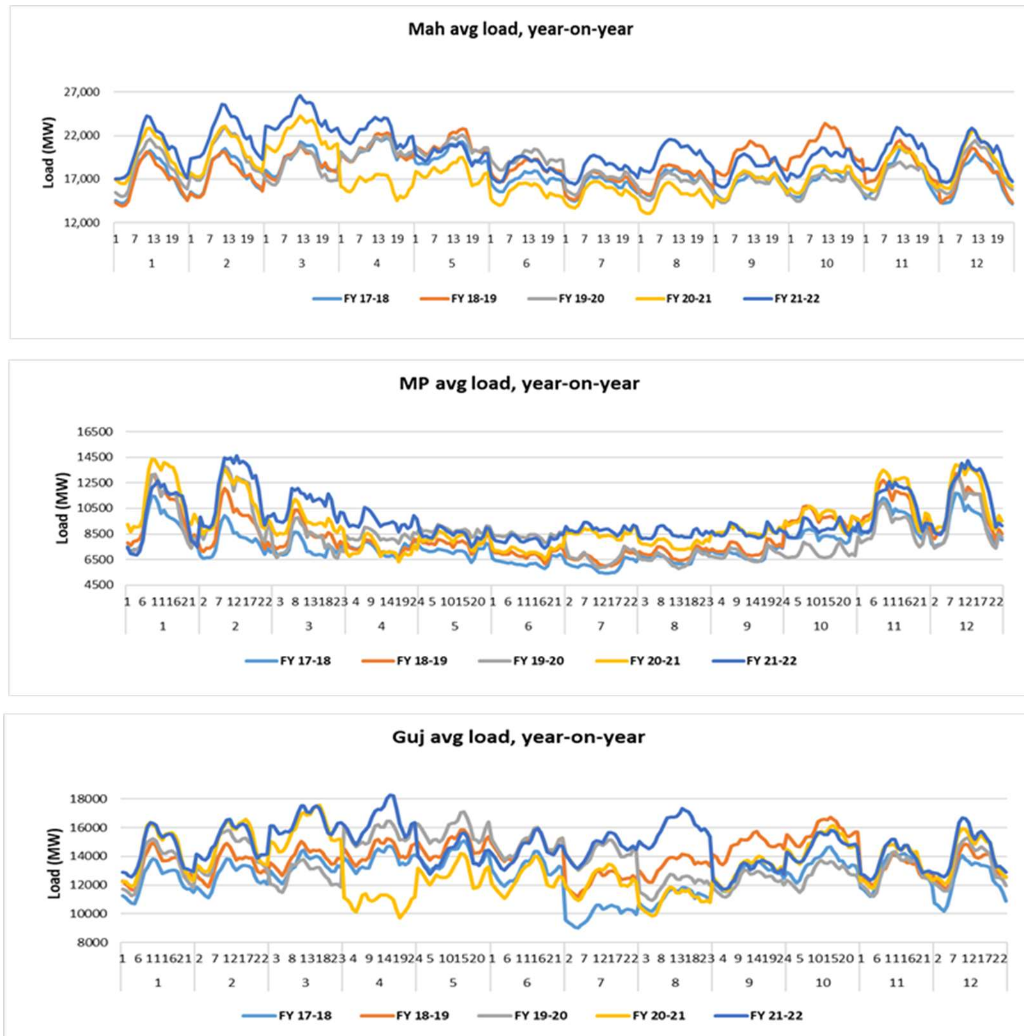

Figure 15: State-wise Avg Load Curve

15.12.2 State-wise Solar and Wind Capacity Addition

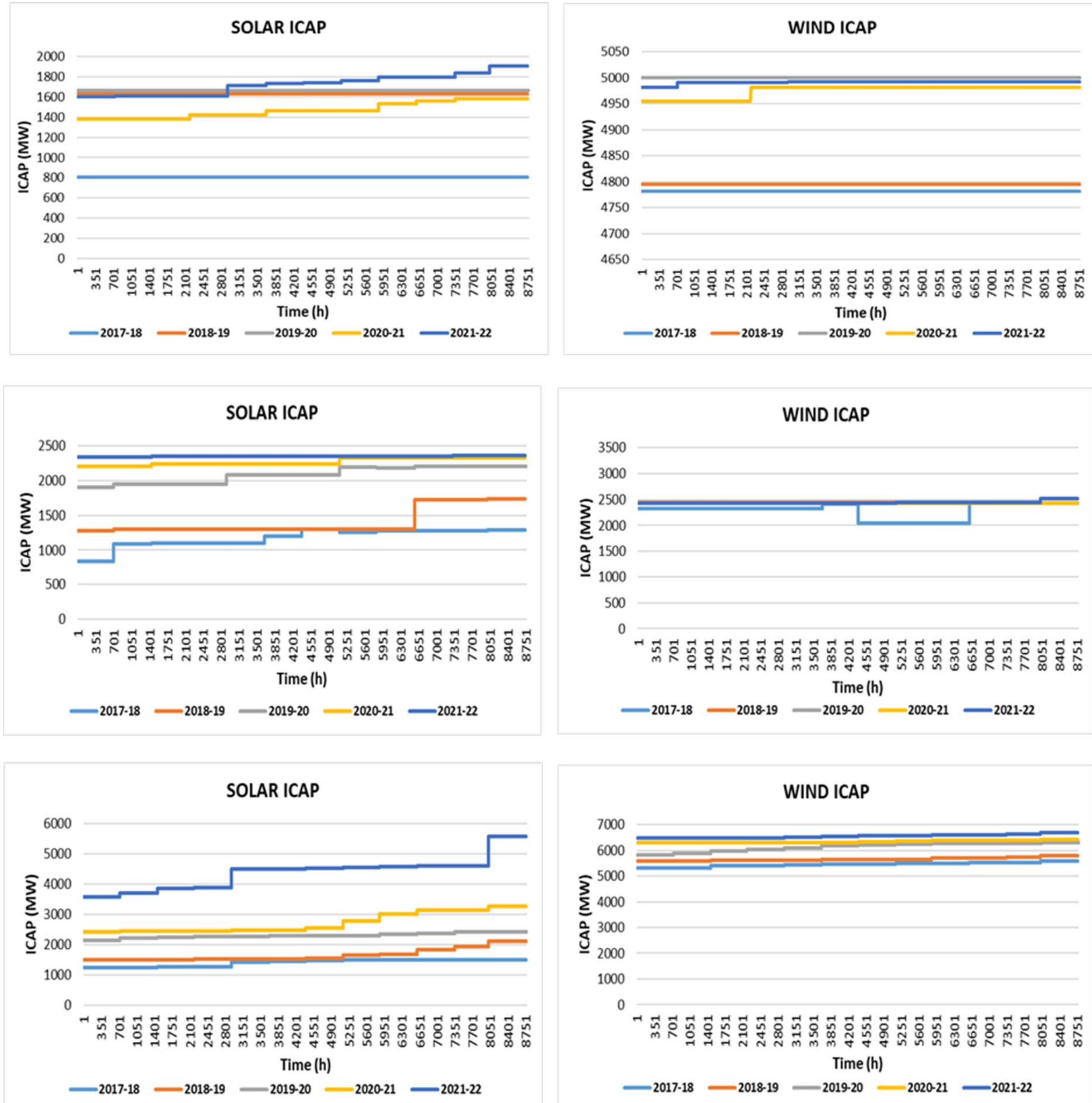

Figure 16: State-wise Solar and Wind Installed Capacity (actual)

15.12.3 State-wise Solar and Wind Generation

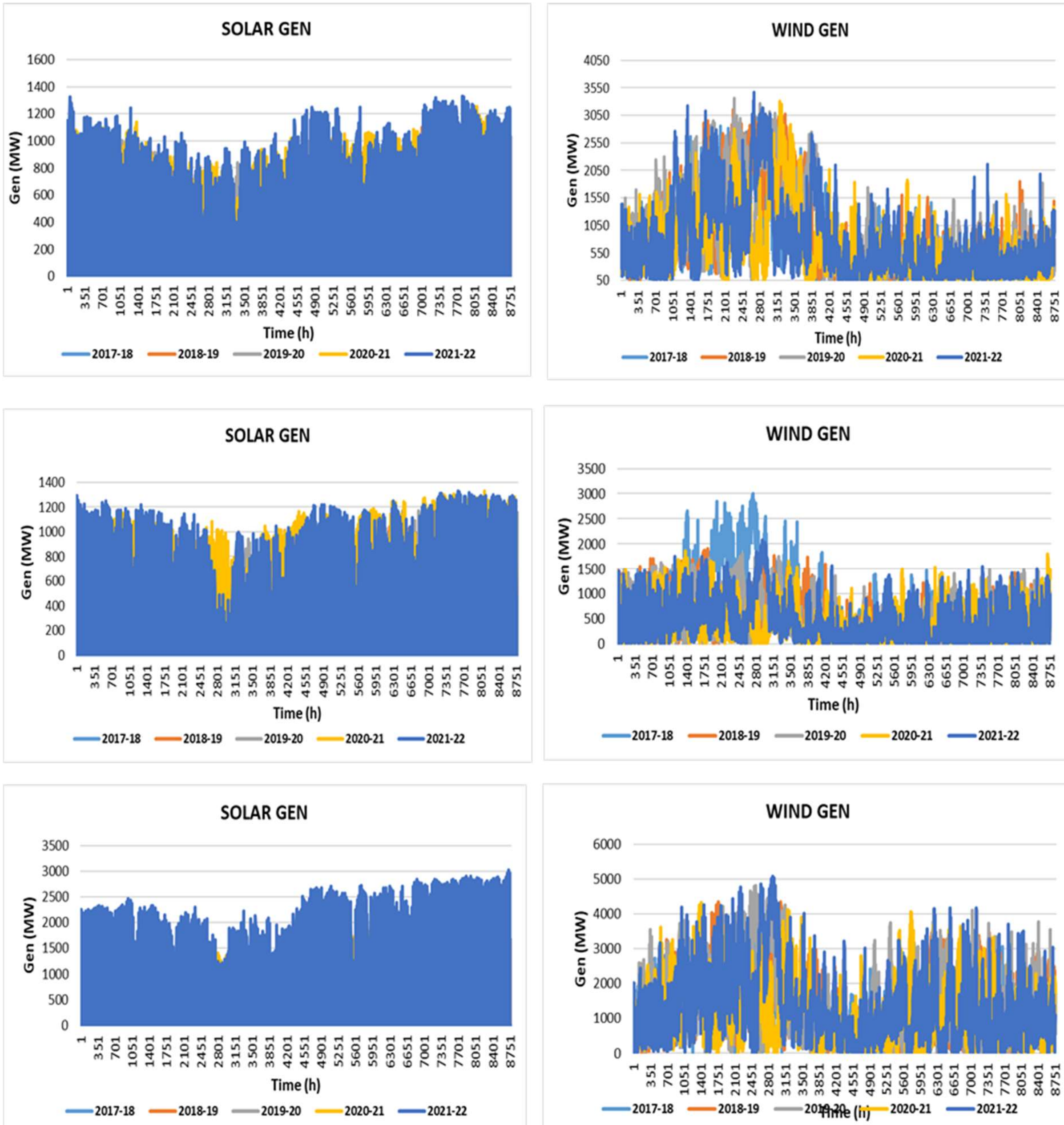

Figure 17: State-wise Solar and Wind Generation (actual)

15.12.4 State-wise CC Calculations

Table 7: CC Calculation for States

2021-22	IC based Gen for top 250 Hrs (MWh) (A)	Generation during top 250 Net Load Hours (MWh) (B)	CC (%) (C) C = B/A
Maharashtra			
Solar	4,76,750	2,42,219	51%
Wind	12,48,014	77,892	6%
Total vRE	17,24,764	3,20,111	19%
Madhya Pradesh			
Solar	5,90,015	2,37,189	40%
Wind	6,29,957	26,073	4%
Total vRE	12,19,973	2,63,263	22%
Gujarat			
Solar	13,91,566	4,03,407	29%
Wind	16,69,639	3,47,932	21%
Total vRE	30,61,205	7,51,339	25%

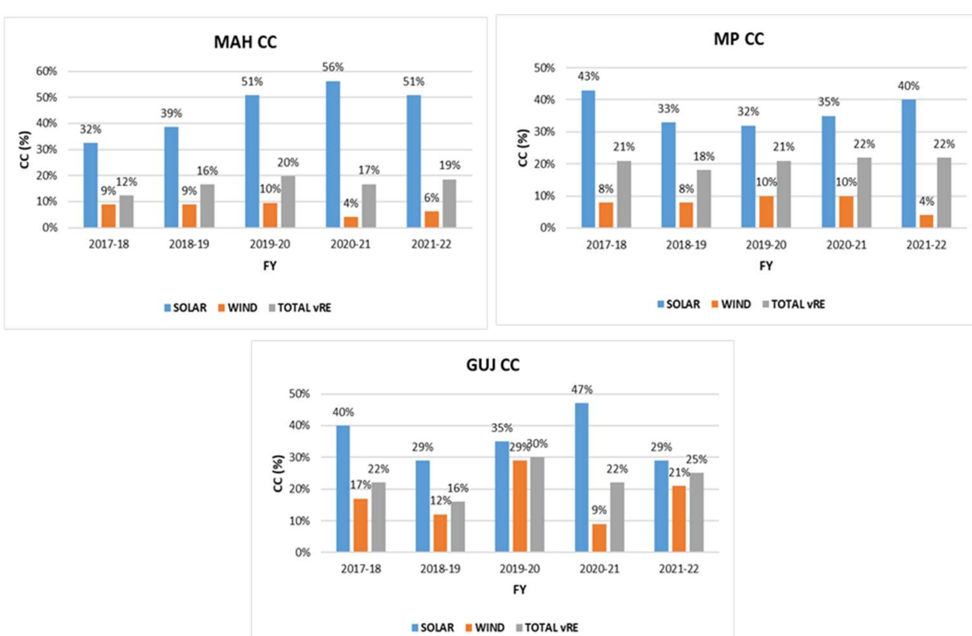

Figure 18: State-wise YoY CC

15.12.5 State-wise Capacity Surplus/Deficit

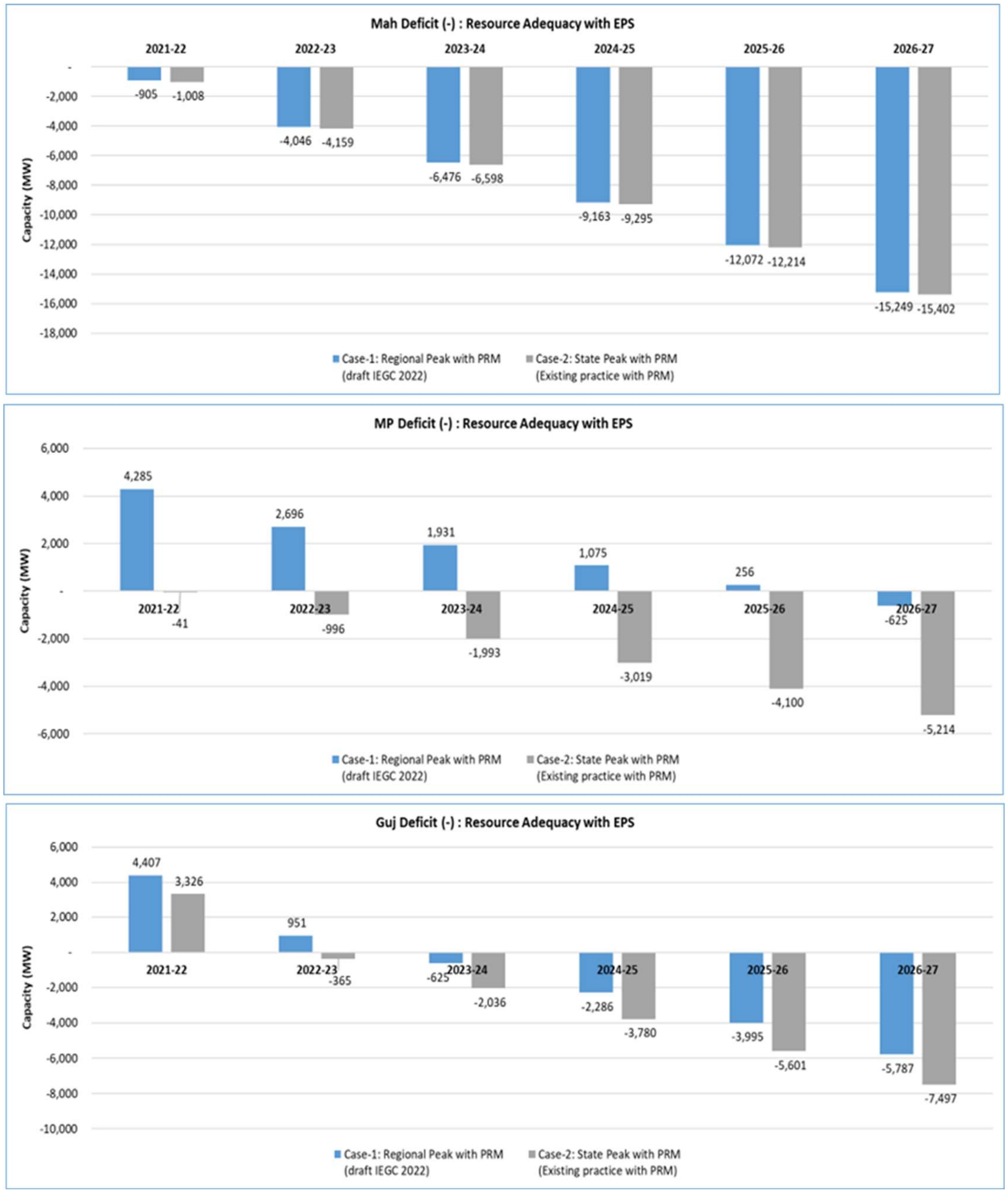

Figure 19: State-wise YoY Surplus/Deficit

15.12.6 State-wise RA Requirement for FY27

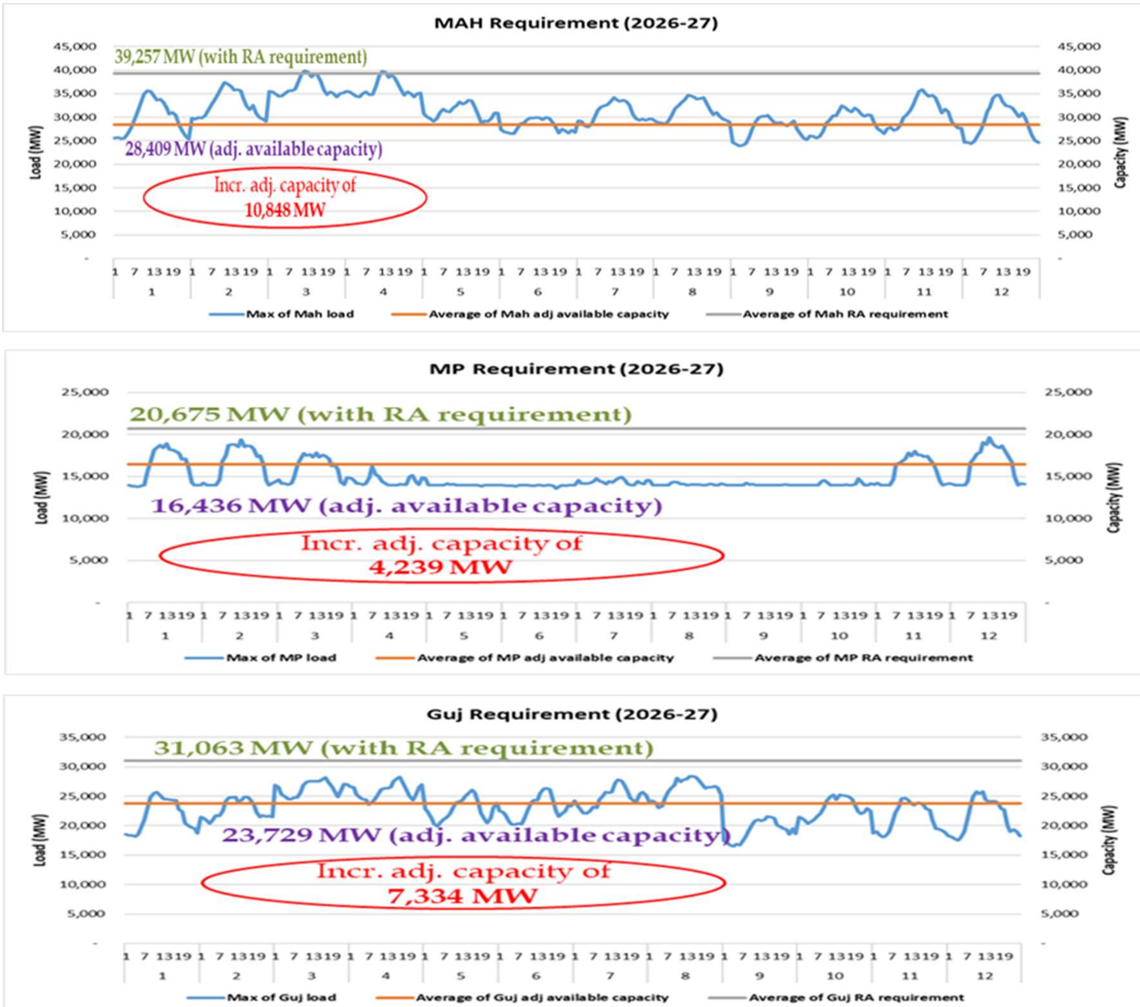

Figure 20: State-wise RA Requirement for FY27

15.12.7 State-wise Procurement Type and Tenure

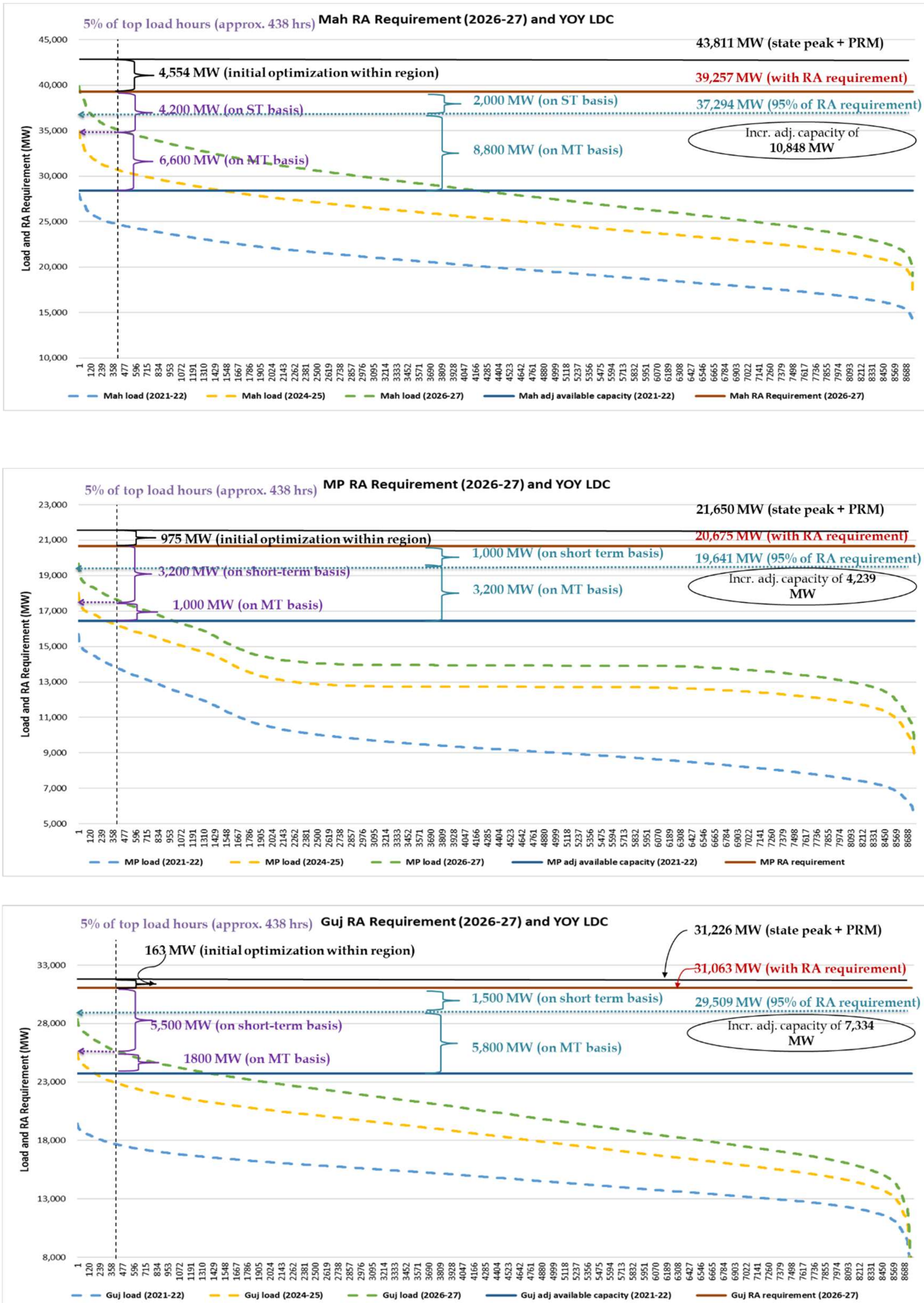

Figure 21: State-wise Procurement Type and Tenure