DRAFT GUIDELINES

FOR

RESOURCE ADEQUACY PLANNING

FRAMEWORK FOR INDIA

CENTRAL ELECTRICITY AUTHORITY
SEPTEMBER 2022

INDEX

SECTION – 1

Introduction

1.1. Indian power sector has witnessed several key developments in the recent years which require a redesign of electricity markets. With a clear mandate to add more renewable energy, which is inherently variable and intermittent in nature, primary amongst the redesign measures would be to ensure adequacy in generation capacity contracting such that demand is reliably met in future, in all the time horizons. Resource adequacy planning has been thus felt necessary on the back of following developments:

a) With lower-than-expected growth in peak demand combined with an overhang of untied installed capacities, state distribution / procuring utilities have ceased holding competitive bid processes for long-term PPAs. This will create issues in the short run as well as over the longer planning horizon, as conventional power plants require substantial planning and lead times and shortfalls in capacity are difficult and expensive to be rectified quickly in the future.

b) Presently, states do their power procurement planning and contracting by considering all the possible options available to them. However, sometimes details of all generation capacity available at regional or National level may not be available with states. Such a situation necessitates designing of a mechanism to ensure adequacy of resources through sharing of reserves and prevent a potential surplus / deficit situation, in an optimal way.

c) The Government is committed to introduce suitable market mechanisms and deepen the spot markets. This is expected to lead to efficient wholesale electricity prices which would threaten the profitability of conventional power plants due to both shorter runtimes and increasing need for flexibility. This would necessitate a mechanism to ensure that conventional resources are compensated adequately for their cost of investment as they take on the role of providing spinning/ non-spinning reserves.

d) The extant practice of ensuring adequacy in generation contracts is reliant on the jurisprudence of the distribution utilities to estimate their demand accurately and plan for power procurement. Distribution utilities currently make good any short-term deficiency by procuring electricity from spot markets and sell any surplus electricity available with them, back to the same spot market. There is a general impression that this is sufficient to manage the variability and intermittency of RE generation and fluctuations in demand.

e) The country has set a bold vision of ensuring at least half its energy generation from non-fossil fuel sources by 2030. This will result in an increasingly higher share of variable renewable energy sources being integrated into the grid and demands a fresh look at the manner in which distribution licensees contract for power. This is also important because with increasing penetration of VRE (Variable Renewable Energy) and distribution licensees seeking to transition away from long-term PPAs, there exists the risk of making erroneous calls on contracting. Over the planning horizon it can lead to over or under provisioning of generation, both of which are undesirable from reliability or cost considerations and lead to surplus/deficient situations in the short term as RE generation fluctuates.

f) Currently, there is no mechanism to enforce and monitor whether adequacy of supply is being met by state utilities by carefully integrating availability of resources in other states and regions. Hence, situations like overhang of capacity or demand deficits have been common in the recent past.

1.2. To optimize power procurement costs, the Central Government has been focused on the development and deepening of time-sequential electricity markets to ensure optimal capacity development and efficient operation of electricity generation. Now there is a need to institutionalize a Resource Adequacy framework to be followed by distribution licensees for power procurement and capacity contracting. Resource Adequacy is generally defined as a mechanism to ensure that there is an adequate supply of generation or demand responsive resources to serve expected peak demand reliably. In this context, reliability is generally measured through instances / probability of system peak exceeding the installed generation capacity which is effectively available. Adherence to such a framework would ensure a reliable and efficient operation of the power system across all timeframes.

1.3. Central Electricity Authority (CEA) hereby is issuing the guidelines for Resource Adequacy framework for the Indian electricity sector. The guidelines shall be followed by the various institutions and stakeholders, as named as part of this guidelines, and supporting rules, regulations and orders can be enacted as required.

1.4. Changes, if any, required in the regulations for implementation of the guidelines shall be done by the Appropriate Commission.

1.5.

SECTION – 2

Key Challenges faced in Generation Planning and recent developments

2.1. Increasing share of variable renewable energy and higher frequency of extreme weather events due to climate change have necessitated the development of a resource adequacy framework that comprehensively covers several aspects to understand and address the likely power supply position:

2.1.1. A key aspect of Resource adequacy planning is to ensure that adequate generation capacities are available, round-the-clock, to reliably serve demand, under various scenarios. This naturally translates into the need for ensuring adequate reserve margin, which could cater to varying levels of demand and supply conditions in the grid. In the wake of high RE generation, it is important to understand demand-supply situation in the grid in more granularity.

2.1.2. It is necessary to develop a resource adequacy framework to suggest the optimal capacity mix required to minimize the total system cost in meeting the projected demand for the future. This should include determining new generation capacities to meet future demand growth.

2.1.3. The resource adequacy framework should holistically look at a 5 – 10 year time horizon. This is critical, considering the longer gestation period required for planning and constructing most generation technologies.

2.1.4. It is important to determine the duration of time when a loss of load can occur due to demand forecast errors, generation forecast errors, outages, weather phenomenon etc. Scenario planning under multiple (>100) load and supply positions outage conditions, RE variability, etc. should be performed and integrated in the resource adequacy planning framework.

2.1.5. A consideration to include energy storage and other flexible resources, which can be helpful in balancing out the variability and intermittency of RE, should be included for increasing reliability and reducing system costs.

2.1.6. The expected deepening of short-term sale/purchase under bilateral contracts and through collective transactions needs to be considered in the resource adequacy planning exercise. Also, as short-term market gains liquidity, sharing resources through short-term markets, should become an integral part of resource adequacy planning.

SECTION – 3

Key design parameters for RA framework

3.1. **<u>Reliability</u>** is key to power systems operations and hence adequacy of supply needs to be maintained at all points in time. There could be unavoidable outages, due to unforeseen circumstances and reasons, but the integrated resource planning should be such that these outages (loss of load events) are restricted within acceptable limits.

3.2. **Loss of Load Probability (LOLP)** is a 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

Parameter	Definition
Loss of Load Probability (LOLP)	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.

3.3. Additionally, another metric which could be utilized in conjunction with LOLP is the **Expected Energy Not Served (EENS).**

Parameter	Definition
Expected Energy Not Served (EENS)	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. This is an energy-centric metric that considers the magnitude and duration of energy being not served, calculated in megawatt hours (MWh). The metric can be normalized (i.e., divided by total system load) to create a Normalized Energy Not Served (NENS) metric.

3.4. "Normalized ENS" is the total expected load shed due to supply shortages (MWh) as a percent (%) of the total system energy, and therefore represents an overall percentage of system load that cannot be served. NENS provides a better appreciation of the magnitude of the issue which the absolute number EENS does not provide.

3.5. Most systems in advanced electricity markets use LOLP / NENS as the RA planning criteria.

3.6. To meet the prescribed standard of LOLP / NENS conditions, sufficient reserve margins (also known as planning reserve margins) need to be maintained in the system for adequately addressing the load and supply variations. **Planning Reserve Margin (PRM)** is the predominant metric used to ensure adequacy in the system. PRM in a power system is expressed as a certain % of peak load forecast of the system.

3.7. CEA, from time to time, publishes the desired values for reliability indices such as LOLP/NENS required for resource adequacy in India and accordingly estimate the PRM required to optimally maintain at the national level. The LOLP and NENS values adopted by CEA for the purposes of the National Electricity Plan (NEP) are 0.2% and 0.05% respectively.

3.8. Similarly, system studies (generally referred to as **Optimal Reserve Margin study**) can be undertaken by the utilities to determine the PRM through any scientific method as approved by the concerned SERC, provided the determined PRM is higher than the national-level PRM, as guided by CEA from time to time[1]. The methodology for conducting the Optimal Reserve Margin study is highlighted in **ANNEXURE A**. Alternatively, the utilities can consider a minimum PRM, as guided by CEA from time to time.

3.9. The PRM is to be used by utilities in their resource adequacy and capacity planning. The capacity planning by utilities should be developed through an Integrated Resource Plan (broad methodology has been described in **SECTION – 4**).

---

[1] In future amendments, once the RA process is established, utilities can conduct their own optimum reserve margin studies to determine the optimal PRM as per the methodology prescribed in ANNEXURE A and ANNEXURE C. In case of any shortfall, NLDC shall either communicate the shortfall to the SERC or facilitate a national-level auction for the balance capacity with participation from distribution licensees with capacity shortfall

SECTION – 4

Integrated Resource Planning to arrive at optimal capacities in the long-term and fulfil Resource Adequacy

4.1. An Integrated Resource Plan (IRP) is a plan prepared by a utility to determine the target generation capacities for meeting the forecasted **energy** demand over a specified future period. An IRP usually answers the following questions:

a) How to plan a resource portfolio for the future (generation, retirements, etc.)?

b) What type of generation should be built/contracted to meet the demand and how much?

c) How can the system be optimized for delivering reliable power at least-cost?

4.2. An IRP exercise requires many inputs, such as demand profiles, demand growth rates, contracted capacities, costs for new capacities, etc. The model can optimize for a wide range of technologies such as renewable resources, conventional resources, distributed energy resources (DER), demand-side management (DSM) resources and energy storage resources.

4.3. An IRP model is a medium to long-term planning model, usually developed through a Mixed Integer Linear Programming (MILP) framework, to simulate the demand and supply positions with due recognition of the various operational constraints. Such a software/ model can be custom developed or can be commercially procured and solved through commercially available solver technologies.

4.4. The model would undertake a least cost generation optimization to meet the demand such that it minimizes the overall system cost - including capital costs, operations and maintenance costs, costs to procure spinning reserves, fuel costs, transmission cost, start-up, and shut-down costs. The optimization includes all constraints related to power plant operations like ramp-up / ramp- down limits, start-up/ shut-down limits and costs, generation limits, energy storage operations, interconnection limits (import/export), renewable addition targets, retirement schedules of existing generation plants, etc. The model needs to be run for the planning horizon.

4.5. To prepare the Resource Adequacy plan, data on the following needs to be obtained:

a) Planning Reserve Margin as prescribed by CEA or as determined by the utility and approved by the SERC.

b) Actual demand met by the state utility in granular time block resolutions (hourly) for last 5 years

c) Estimated load growth during the planning period

d) Technical parameters of conventional generation plants viz. Capacity (MW) (for existing and planned capacities), Auxiliary Consumption (MW), Maximum and Minimum Generation Limits (MW), Ramp Up and Ramp Down Rate (MW/min), Minimum up and down time, Plant Availability Factor (% of time), etc.

e) Potential investment options and technologies

f) Capacities and generation profile of renewable generation

g) Capital costs, variable costs, O&M costs, reserve offers, start up and shut down Cost of conventional generators, etc.

h) Historical forced outage rates of generation capacities

i) Tie line details and transmission expansion plans

j) Spinning reserve requirements

k) RPO and Energy Storage Obligation targets, etc.

4.6. The hourly demand profile for the utility needs to be projected over the planning horizon, based on the forecasted values of annual energy requirement and peak demand trajectory. The annual energy requirement and peak demand shall be forecasted using trend method, time series, econometric methods, or any state-of-the-art methods. The projected hourly demand for the future years will be used as inputs into the model. It is essential to ensure that the IRP model chosen is capable of simulating on an hourly chronological resolution[2]. This is necessary to capture the behaviour of the system with respect to ramping of conventional generation, profiles of RE generation, behaviour of energy storage, etc.

4.7. Resource adequacy shall be determined based on the resource availability and accessibility after due consideration of sharing of reserves from other utilities/ states through the national markets or through bilateral mechanisms. This is addressed through considering suitable import/ export limits and appropriate derating of such limits, if required.

4.8. Once the demand profiles are established for all the future years, the model would undertake an optimization exercise to minimize the total system cost to meet the future demand

[2] To limit the computational burden of simulating all 8760 hours on a chronological resolution in a year, the standard practice is to select representative periods. The representative periods chosen are reflective of various projected demand and supply profiles for the base year and future years

including violation/penalty terms for the constraints under consideration. Following constraints should be considered while modelling:

a) **Planning Reserve Margin / Resource Adequacy Requirement:** The Resource Adequacy Requirement (RAR) constraint ensures that each that the total Resource Adequacy (Generation capacity) of the utility fulfils the Planning Reserve Margin as determined by CEA or by the utility's own studies, as approved by the SERC. From the demand side point of view, the resource adequacy requirement for each utility is computed as:

$$RAR = contribution^{3}\ to\ forecasted\ national\ peak\ demand\ in\ GW \times (1 + PRM)$$

From the supply side point of view, the RAR is the sum of the "firm capacity" or "capacity credits" of contracted / planned capacities (including renewables, storage, other resources such as demand response) along with derated interconnection limits (imports).

$$RAR = \sum_{i=1}^{num\_solar} Solar\_Capacity * Solar\_Capacity\_Credit + \sum_{i=1}^{num\_wind} Wind\_Capacity * Wind\_Capacity\_Credit + \sum_{i=1}^{num\_hydro} Hydro\_Capacity * Hydro\_Capacity\_Credit + \sum_{i=1}^{num\_thermal} Thermal\_Capacity * Thermal\_Capacity\_Credit + \sum_{i=1}^{num\_nuclear} Nuclear\_Capacity * Nuclear\_Capacity\_Credit + \sum_{i=1}^{num\_storage} Storage\_Capacity * Storage\_Capacity\_Credit + \sum_{i=1}^{num\_other} OtherResource\_Capacity * OtherResource\_Capacity\_Credit + \sum_{i=1}^{num\_other} Import\_limit * capacity\_credit$$

Both, supply side and demand side RAR should match. The Thermal capacity credit is calculated by reducing the Auxiliary consumption and the Forced Outage rate from the installed capacity. Planned Outage rate is generally not considered, as planned maintenance can be carried out during low net-demand periods and thus does not affect reliability.

The capacity credits for generating resources and demand response resources to meet the national peak will be estimated by CEA[4]. The capacity credits published by CEA for each

[3] Contribution is calculated as utility's coincident peak during the top 100 national peaks. Coincident peak is defined as the utility's demand at the time of the national peak demand.
[4] The methodologies that can be used to determine capacity credits for generating resources and demand response resources are outlined in **ANNEXURE B.**

resource type may differ between existing and new resources and between resources in different regions. For example, a solar plant in the southern region will have a capacity credit which could be different compared to a solar plant in the northern region. Similarly, an upcoming wind plant could have a different capacity credit compared to an already commissioned wind plant in the same region. Utilities will use these capacity credits when planning to meet their RAR. For example, a utility having a PPA with an existing solar plant located in a southern state would use the capacity credit of existing solar plants in the southern region.

b) **Portfolio balance constraints:** The portfolio balance constraints ensure that the total generation within a region and the import of power to the region is equal to the sum of the demand, the exports from the region, any energy not served and curtailment, for each hour.

c) **RE Generation constraints:** For renewable resources, such as solar and wind, the generation is constrained as per the hourly profile of the resource. Historic profiles of renewable sources will be used to generate the hourly profiles. Additional constraints to ensure that the utility's overall renewable generation targets are met, should also be included.

d) **Conventional Generation constraints:**

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

e) **Storage constraints:** Due to the intermittent nature of renewable generation, the need for resources which can store surplus energy and dispatch the stored energy during low RE periods becomes vital. Storage charge and discharge at any instant are constrained by the storage level or the state of charge (SoC) of the storage resource, and the maximum charge / discharge limit. The resource can only discharge if there is sufficient energy present due to prior charging of the resource. To implement this, considering the chronological sequence of time is also important. Since storage resources convert electricity to other forms of energy, there are also some efficiency losses (round-trip efficiency) which must be captured. Different technologies will have different discharge periods (energy limits), power outputs (maximum charge / discharge) and levels of efficiency.

f) **Operating (Spinning) Reserve constraints:** Operating reserve constraints ensure that enough resources are in the system and kept online or on standby each hour to account for load forecast errors, intermittency of renewables or meeting contingencies in the real time. The operating reserve requirement thumb rule should be defined based on discussions with the state SLDC and be considered as an input parameter to the model. Like the load balance constraints, a penalty value should be attached to any unserved reserve requirement.

g) **Demand Response:** Potential for demand side management such as shifting of load or demand response can be considered while undertaking the IRP. Constraints such as periods when load shifting can occur, the maximum quantum in an hour and the maximum quantum of load which can be shifted would need to be included.

4.9. The output of the model would be the **quantum and type of resources** required in the portfolio of a utility to meet the demand in an optimal (least cost and secure) manner. The model shall give the **year-on-year optimal generation** (conventional + Renewable) and **storage capacities required to meet the system demand** and the **planning reserve margin** condition securely and at least cost.

SECTION – 5

Institutional mechanism for Resource Adequacy and Compliance Monitoring

5.1. Central Electricity Authority (CEA) shall publish Long-term National Resource Adequacy Plan (LT-NRAP) which shall determine the optimal Planning Reserve Margin (PRM) requirement at the All-India level conforming to the LOLP (Loss of Load Probability) and NENS (Normalized Energy Not Served) targets.

a) The report shall publish the national-level PRM and the reliability indices (LOLP and NENS) as a guidance for all the states to consider while undertaking their RA exercise.

b) The report shall also publish the Optimal Generation mix for the next 10 years required to ensure that the national-level system is RA compliant while meeting the All-India demand at least-cost. This shall guide capacity buildout investments in the country.

c) The report shall also publish the capacity credits for different resource types on a region-wise basis.

d) The report shall specify the state's contribution towards coincident national peak.

e) The LT-NRAP shall be updated annually.

5.2. POSOCO / NLDC shall annually publish a one-year look-ahead Short-term National Resource Adequacy Plan (ST-NRAP) which shall include parameters such as demand forecasts, resource availability based on under-construction status of new projects, planned maintenance schedules of existing stations, station-wise historic forced outage rates and decommissioning plans.

5.3. The hourly demand forecasts used by CEA and POSOCO / NLDC should be aligned with the projections as per the individual Distribution Licensees. STU / SLDC, on behalf of the distribution licensees in the State shall provide to CEA and POSOCO / NLDC by the month of June every year, the details regarding hourly demand forecasts for the next 5 years, assessment of existing generation resources and such other details as may be required for the LT-NRAP and ST-NRAP.

5.4. The LT-NRAP and ST-NRAP shall be published by the month of August for the period starting from the month of April in the next year.

5.5. Each Distribution licensee shall undertake an Integrated Resource Plan (IRP) for a 10-year horizon (Long-term Discom Resource Adequacy Plan (LT-DRAP)) which is to be submitted to the respective State Electricity Regulatory Commission (SERC) for their approval. The LT-DRAP must be undertaken as per the methodology outlined in SECTION-4 of this guidelines. Distribution licensees may opt to simply adopt the PRM as published by CEA or may undertake Optimal Reserve Margin studies using the reliability indices published by CEA in LT-NRAP.

a) Distribution licensees are free to consider higher PRMs or more stringent reliability constraints, depending on their consumer mix portfolio, subject to approval from the SERC

b) In states where there are multiple distribution licensees, the respective STU / SLDC shall allocate the distribution licensee's share in the national coincident peak within 15 days of the publication of LT-NRAP.

c) The distribution licensees are to complete their LT-DRAP by taking suitable inputs from the LT-NRAP like PRM, coincident peak, capacity factors, etc., and submit their plans to the SERC by the month of October for the period starting from the month of April in the next year.

d) The LT-DRAP shall be performed by the distribution licensees on an annual rolling basis. Subsequent LT-DRAP runs are to consider the contracted capacity as a part of the system and shall optimize for additional capacity required

5.6. Based on the optimal resources identified by the LT-DRAP, the distribution licensees shall plan to contract the capacities suggested by the LT-DRAP to be procured to meet their PRM at the coincident national peak. The distribution licensees shall demonstrate to the SERC 100% tie-up for the first year and a minimum 90% tie-up for the second year to meet the requirement of their contribution towards meeting coincident national peak. Only resources with long / medium / short-term contracts will be considered to contribute to the PRM. Power procurement through the power exchanges, such as the Day-Ahead Market segment, will not be considered.

For subsequent three years, the distribution licensee shall submit a plan for 100% capacity tie-ups to meet estimated requirement of their contribution towards meeting coincident national peak for SERC's approval.

5.7. Distribution licensees, through the LT-DRAP, should also demonstrate to the SERC, their plan to meet their Peak demand with a mix of long-term, medium-term and short-term means, including power exchanges. Distribution licensees shall also demonstrate their plans to contract with existing capacities (for shorter-term needs) and plans to build up future capacity (for long-term needs).

5.8. Once the distribution licensees have contracted the capacities, the distribution licensees shall submit the contracted capacities for the ensuing year to the respective STU / SLDC by the month of January. The STUs / SLDCs shall aggregate the total contracted capacities at the state level and submit the information to the respective RLDC. The RLDCs shall aggregate the capacities at the regional level and submit the information to the POSOCO / NLDC by the month of February. POSOCO / NLDC shall aggregate the capacities at the national level and check compliance with ST-NRAP and identify shortfall for the ensuing year, if any. In case of shortfall, POSOCO / NLDC shall either communicate the shortfall to the distribution licensees for compliance or facilitate a national-level auction for the balance capacity[5] with participation from distribution licensees with capacity shortfall[6]. The contracting for the balance capacity shortfall shall be completed by the month of March prior to the start of the delivery year (1st April).

5.9. The SERCs shall be responsible for the Resource Adequacy compliance by the distribution licensees. Non-compliance shall render the concerned distribution licensee liable for payment of resource adequacy non-compliance charges as may be specified by the respective SERCs.

5.10. Based on initial experience of implementation, CEA may come out with technical standard/regulations for implementing the resource adequacy framework.

5.11. A schematic illustrating the Resource Adequacy implementation timelines is given in **ANNEXURE D**.

[5] $balance\ capacity = (1 + National\ PRM) \times NationalPeak\ - sum\ of\ contracted\ capacities$

[6] $capacity\ shortfall = (1 + National\ PRM) \times Demand\ during\ Coincident\ Peak\ - sum\ of\ contracted\ capacities\ by\ the\ licensee$

ANNEXURE A

Determination of LOLP / NENS, Optimal Planning Reserve Margin (PRM) and Resource adequacy targets

A.1. The optimal level of "target" or "planning" reserve margins should be arrived at through measures such as "Loss of Load Probability" and NENS (Normalized Energy Not Served). Loss of load can happen due to various factors such as:

a) Forced outages/planned maintenance of conventional generation

b) Real time unforeseen excursion in demand/demand forecast errors

c) Generation forecast errors /RE intermittency

A.2. A loss of load occurs when the net system load (Gross load – RE generation) exceeds available conventional generation in a particular time. Appropriate LOLP / NENS metrics should be considered based on consultation with stakeholders as well as international best practices.

A.3. The first step in determining the Resource Adequacy targets would be to determine the target generation capacities at a nominal Planning Reserve Margin using an **IRP** model.

A.4. Once the generation capacities are estimated, it becomes important to estimate the several demand-supply patterns and then determine if the required generation capacity in the system can always meet demand reliably by calculating the loss of load and energy not served. A natural outcome of the above objective is to construct many possible future scenarios based on the uncertainty surrounding the demand for power, intermittency of RE sources, availability of power plants, tie-lines, inter-state/intra-state and inter-regional transmission constraints etc. These future scenarios should be constructed based on following indicative parameters viz:

- Demand variations / forecast errors
- Hydro conditions (normal, wet, or dry years)
- Scheduled and unscheduled outages of power plants and interconnectors
- Generation forecast errors, etc.

A.5. **Multiple future scenarios** should be created using stochastic models to account for **uncertainty** and analyse any occurrence of lost load. Each such future scenario is established based on historical data. The key inputs for generating future possible states are as follows:

a) **Demand volatility:** Uncertainty in demand can be built into the model through two categories, long-term uncertainty driven by underlying effects such as load growth forecasting errors, unanticipated economic growth, etc., and short-term uncertainty which can be defined as the sum of a typical (or mean) monthly load pattern for the day and the historical deviation observed from the mean load.

b) **Conventional generator outages:** Planned outages and scheduled maintenance for thermal generators will be scheduled either based on historic patterns or during low demand periods based on a uniform probability distribution. For forced outages, Monte Carlo draws for each unit based on historical outage rates may be simulated.

c) **Variable Renewable Generation Intermittency:** To capture the intermittency of solar and wind plants, PV, and wind generation data of past several years can be analysed and multiple scenarios which match the projected CUF levels may be created. Annual CUF projections may also be generated through Monte Carlo Draws based on the annual CUFs observed in the historical profiles.

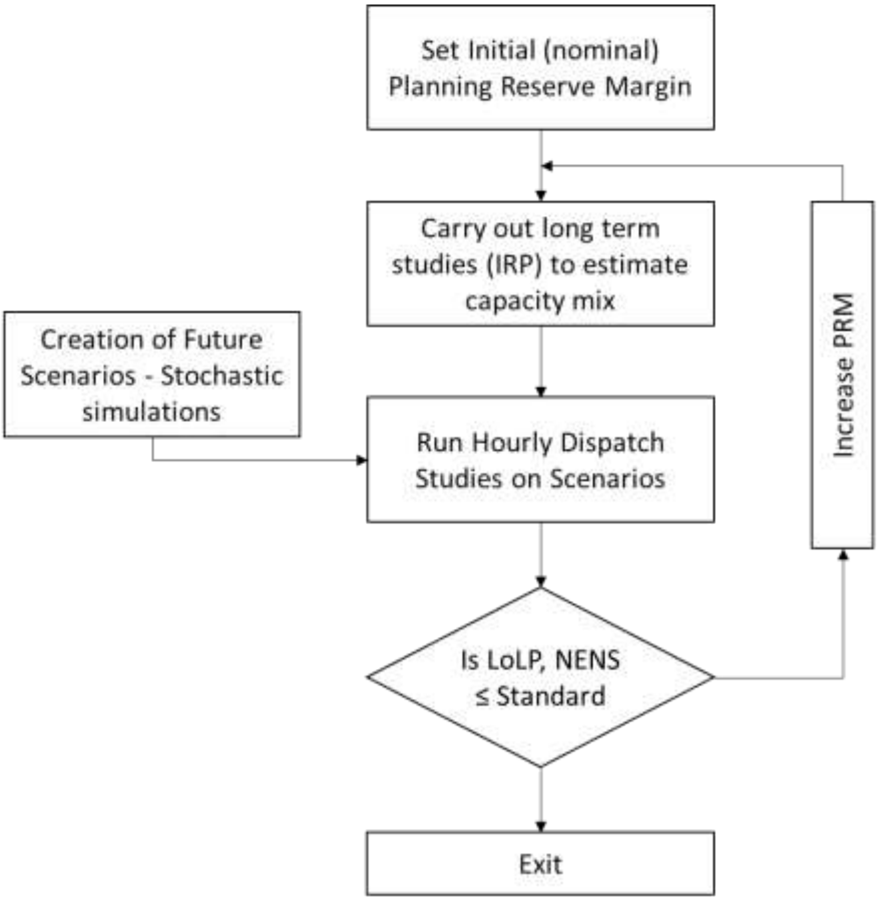
d) **Availability of ATC for short-term import:** In the utility-level / state-level planning, short-term import is limited to the available transfer capability. However, as there is no visibility about the power generation profile of other states, unpredictability in the availability of tie line power form other utilities and regions must be factored in. To incorporate the above-mentioned unpredictability, availability of each tie line for each hour can be derated by a factor drawn from a probability distribution using Monte Carlo Simulations. Details on the appropriate probability distribution to be considered may be provided by NLDC / CEA from time to time.

A.6. Once the demand-supply projections / scenarios are established and the possible future states are predicted, a demand-supply matching simulation with the estimated capacities should be performed. The objective of such a simulation would be to use the capacities obtained from the IRP to meet the demand and assess the duration of the loss of load events and energy not served for each scenario and for the specified planning margin / IRP mix.

A.7. The above process needs to be then iterated by **incrementing** the **planning reserve margin levels** until the **desired levels of LOLP / NENS** is achieved in the system. This iterative model would enable identification of a target PRM level as per the desired LOLP figures. An illustrative flowchart of the process is shown in Figure 1.

A.8. While arriving at the target LOLP / NENS figures, consideration should be given to system costs. The objective should be to have an optimal level of Reserve margins which would represent the optimal trade-off between system costs and reliability. For this purpose, an evaluation of the marginal cost of reducing load shed is required. The PRM at which the marginal cost of reducing load shed is equal to the Value of Lost Load as defined by the utility is the economically optimal PRM. The procedure of calculation of marginal cost of reducing load shed is given in **ANNEXURE C**.

Figure 1: Flowchart of the Optimal Reserve Margin Study



ANNEXURE B

Determination of capacity credits for Renewable resources

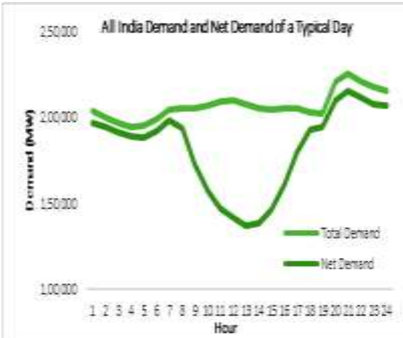
B.1. This step is important for determining how much of energy-limited resources (hydro, wind, solar, storage) will count toward resource adequacy requirements. Generation planning is set to become more complex as larger amounts of weather-based, variable renewable generation are added to the system. This is because resources such as wind and solar PV are intermittent, and their generation may not coincide with periods of peak demand.

B.2. Each generator can provide a "firm capacity," which represents the amount of power the generator can reliably provide. Capacity credit expresses firm capacity as a percentage of the installed nameplate capacity.

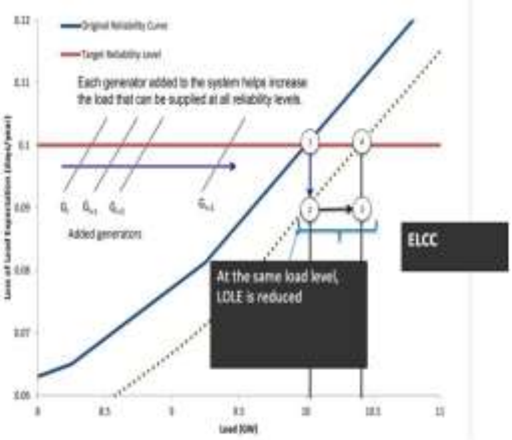
B.3. Following are the various methodologies to determine capacity credits of Renewable energy adopted internationally. These methodologies can also be extended to demand response resources.

a) **Capacity credit approximation with Top Demand Hours**: In this case, a basic approximation of capacity credit can be obtained 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.

b) **Capacity credit approximation with Top Net Load Hours:** In this case, consideration is given to the fact that periods of system stress occur when high demand coincides with low renewable energy generation. A metric called 'net load' is defined as 'total renewable energy 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, net load is a better proxy for system stress for new capacities than peak demand. In this method, capacity credit can be obtained by averaging the contribution of a generator / generator class during top net load hours.



c) **Expected Load carrying capability:** In this method, a model uses an hourly time-series demand data for a particular period. The model also uses the availability of different generation resources in each hour of the year. Random outages of generators are also applied considering the historical and expected outage conditions. Determine supply matching is used to determine the LOLP of the system.



- To calculate capacity credit, the model first removes a generator from the system and calculates the system LOLP. This represents Point 1 in the system reliability curve, as shown alongside.
- 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 the curve shifts right to Point 2 (system reliability is higher), and so it can accommodate more load at the previous LOLP (Point 4). The additional load that can be accommodated represents the generator's ELCC.

B.4. The Capacity Factor Approximation with Top Net Load Hours can be considered to determine the capacity credits for new resources and the Top Load Hours methodology can be considered to determine the capacity credits for existing resources. The ELCC method can be adopted later, once the required capabilities and data are available with the state utilities.

B.5. The utilities are to plan their firm capacity as per the coincident peak which implies that the capacity credits of all resource types are to be calculated on the national-level load profile.

ANNEXURE C

Marginal Cost of Reducing Load Shed

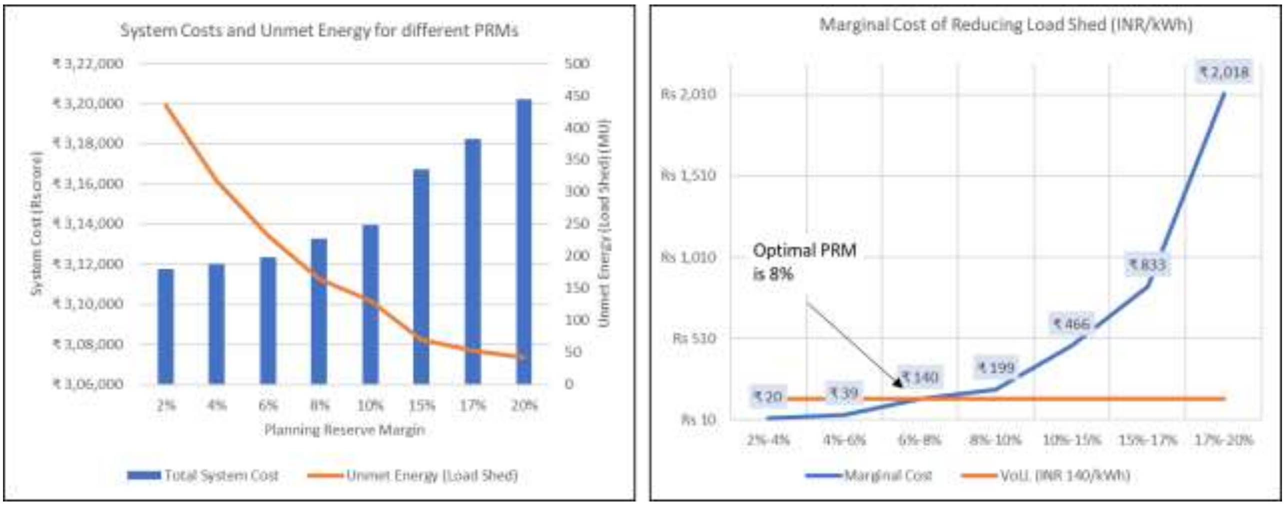
C1. The marginal cost of reducing load shed is the effective increase in cost for every unit of load shed reduced. It is calculated as the increase in system costs by the reduction in load shed:

$$Marginal\ Cost = \frac{System\ Cost_{PRM_{i+1}} - System\ Cost_{PRM_i}}{ENS_{PRM_i} - ENS_{PRM_{i+1}}}$$

C2. The economic optimal planning reserve margin is the planning reserve margin at which the marginal cost of reducing load shed is equal to the value of lost load. Utilities can rely on this planning reserve margin in case they decide to plan beyond the minimum PRM as determined by CEA.

Illustration: An illustration of the calculation of marginal costs of reducing load shed is shown in Figure 2. The capacity expansion planning model is run for different PRMs between 2% and 20%. Based on the capacities obtained, the system costs are calculated. Demand-supply matching using these capacities on future scenarios created using stochastic simulations are used to obtain the total load shed (unmet energy). Based on the system costs and unmet energy (graph on the left), the marginal cost of reducing load shed (graph on the right) is calculated using the formula in C1. Assuming a Value of Lost Load (VoLL) of INR 140/kWh, the optimal PRM would be around 8%.

Figure 2: Illustration of Calculation of Marginal Cost of Reducing Load Shed



ANNEXURE D

Resource Adequacy Implementation Timeline

Entity	Description	Jun'22	Jul'22	Aug'22	Sep'22	Oct'22	Nov'22	Dec'22	Jan'23	Feb'23	Mar'23
STU / SLDC	STU / SLDC, on behalf of the distribution licensees in the State shall provide to CEA and POSOCO / NLDC the details regarding hourly demand forecasts for the next 5 years, assessment of existing generation resources and such other details required for LT-NRAP and ST-NRAP										
CEA	To publish LT-NRAP containing **National PRM, Reliability Metrics, Coincident peak, Capacity credits** and **Optimal Generation mix for 10-year horizon.** LT-NRAP to be updated **annually**										
POSOCO / NLDC	To publish ST-NRAP. ST-NRAP to be updated **annually**										
Discoms	**LT-DRAP exercise for a long-term horizon** (10 years) which is **RA compliant as per Coincident Peak** to be submitted to the respective SERC										
SERC	SERC to approve of discom's contracting plan										
Discoms	To contract capacities as per approved plans										
Discoms	To submit contracted capacities to STU / SLDC										
STU /SLDC	STU / SLDC to submit state-level aggregated capacities to RLDC										
RLDC	RLDC submit regional-level aggregated capacities to NLDC										
POSOCO / NLDC	POSOCO / NLDC to check RA compliance at national level. Any shortfall shall be communicated to the SERC for compliance or is balanced through a national level auction mechanism										

Delivery Period (Apr'23 – Mar '24')