Prayas (Energy Group)'s comments and suggestions on CEA's "Draft discussion paper on methodology for capacity credit of generation resources & coincident peak requirement of utilities under resource adequacy framework"

17-11-2024

In June 2023, Ministry of Power (MoP), in consultation with Central Electricity Authority (CEA), issued the guidelines for Resource Adequacy[1] (RA) under Rule 16 of the Electricity (Amendment) Rules, 2022[2]. As per section 3.1 of the guidelines, CEA is mandated to publish a report specifying the capacity credits for different resource types on a regional basis along with the State/UTs contribution towards the national peak. Towards this, CEA has issued a draft discussion paper specifying methodologies to determine the above parameters and called for public comments by 17th November, 2024.

The paper explores various methods to determine coincident peak demand and the capacity credit for VRE sources. Based on the analysis it recommends,

> *The paper suggests that the solar vs. non-solar methodology may be a better approach for estimating coincident peaks, especially considering factors such as agricultural load shifting and the focus on adding solar capacity. This method could be more relevant than the traditional top 5% demand hour methodology.*
>
> *Based on the analysis, the critical days methodology suggested in the paper is well-suited for estimating the capacity credit of variable renewable energy (VRE) sources, particularly for solar and non-solar hours. By focusing on days with adverse conditions for VRE, the Critical Day analysis provides a more realistic assessment of system performance and resilience. As more VRE is integrated into the system, the critical days methodology becomes even more suitable compared to other methodologies. This approach provides a more accurate representation of the actual performance of VRE sources during critical conditions.*

Broadly, we agree and support both these suggestions. However, Prayas (Energy Group)'s comments and suggestions highlight areas for additional consideration in future RA modelling efforts. In addition, we suggest certain changes towards ensuring a more robust framework.

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[1] https://static.pib.gov.in/WriteReadData/specificdocs/documents/2023/jun/doc2023628218801.pdf
[2] https://powermin.gov.in/sites/default/files/Electricity_Amendment_Rules_2022.pdf

1. Coincident peak methodology: consider multiple demand scenarios

To begin with, it is appropriate to work with the top 5% peak than a single peak demand value. Secondly, to find the coincident peak demand for states, the paper outlines its methodology in section 3.2.1 but it further refines it with an innovative distinction of performing the same analysis in solar and non-solar hours. This too is appropriate given the extremely high reliance that India will have on solar power (with its distinctive diurnal pattern) in the coming years. The result of the analysis is captured below,

> *Statistical analysis for the 15-minute demand data for FY 2023-24 & FY 2022-23 shows that the sum of the 80th percentile of the top 5% coincident peak demand values during the year for states or utilities aligns with the national peak demand value. Therefore, states and utilities will be required to maintain a firm capacity based on the 80th percentile of the top 5% of the coincident peak demand values plus the PRM as mandated by the Central Electricity Authority (CEA).*

While the analysis bears out that 80th percentile of the top 5% coincident peak demand values broadly matches with the national peak, the methodology (section 3.2.1) assumes a single load profile which is project for the next year or two years. The discussion paper considers a single national load duration curve, which is an aggregation of individual state/UT-wise demand curves. These state/UT demand curves are based on the demand profile of the last 2-3 years, and next years projected peak demand and energy requirement. While this may be sufficient to begin with given the novel nature of RA exercise, going forward, multiple demand scenarios factoring in the varied impact of key parameters on the state/UT-wise demand profile, peak demand and energy requirement should be considered. These parameters could be the following:

a) Variations in climate and weather patterns.
b) Increased end-use electrification.
c) Migration of sales to open access and captive consumption.
d) Changes in consumption patterns (E.g., increased consumption in solar hours) etc.

Load profiles are quickly changing, especially from agriculture load shifting to day-time and increase in night time cooling requirements among other factors. Thus, considering multiple demand scenarios (2-3) to decide on the coincident peak contribution of states would make the methodology more robust.

2. Explore distinction across Monsoon and Non-Monsoon seasons

Similar to the solar vs. non-solar distinction in the determination of state wise coincident peaks, another analysis which could be considered by CEA is to consider monsoon and non-monsoon periods. The solar vs. non-solar distinction ensures the preparedness of utilities to meet demand in the absence of solar. However, electricity demand (esp. agriculture), along with generation profiles of wind and hydropower vary seasonally, critically across monsoon and non-monsoon seasons. Therefore, another time dimension to evaluate could be by segregating the national LDC between solar vs. non-solar hours and across monsoon vs. non-monsoon seasons (Table 1).

Table 1: Coincident peak demand in solar/non-solar hours and monsoon/non-monsoon seasons.

	Solar Hours	Non solar hours
Monsoon (June-Sep)		
Non Monsoon (Oct-May)		

3. Need to consider additional relevant factors while determining capacity credits of conventional generation sources

The discussion paper assigns a constant capacity credit to conventional generation technologies like coal & gas (0.7-0.8) and nuclear (0.6-0.7) based on the following formula which considers two factors, Auxiliary consumption, and Availability.

*Capacity Credit of Conventional Sources (Coal, Gas, Nuclear) = Installed Capacity *(1-Auxiliary Power) *Availability*

The paper notes that, *'The capacity credit for conventional sources based on the historical generation figures has been estimated in Table 1'*. It would be useful for CEA to publish this analysis like it has done for coincident peak analysis.

The ability of these technologies to reliably supply power is dependent on additional factors like fuel and water availability, vintage of the plant etc. (See Table 2). The fuel availability also varies across regions and based on fuel source. E.g., Pit head, Non Pit-head with domestic coal, Non Pit-head with imported coal etc. Therefore, it is critical to take such factors into account while determining capacity credits of conventional generation.

Table 2: Examples of reduction in availability due to fuel, water, and vintage.

Particular	Thermal Power Plant (TPP)	Remarks
Water Supply Issues	Parli TPP U6-7	The NAPAF for Parli U6-7 was reduced to 51.45% from 85% in FY 2012-13.
Fuel Supply Issues	Atal Bihari Vajpayee TPP	The NAPAF was initially reduced to 76.5% from 85% for the FY17-FY22 period owing fuel supply issues. Additionally, it was further reduced to 57.38% & 69.47% in FY17 & FY18 for the same reason.
Fuel Supply Issues	Uran Gas Power Plant	The NAPAF was reduced to 34.39% and 35.33% in FY 2020-21 and FY 2021-22 from 85% owing to gas supply issues.

Vintage of Plant	Ennore TPP	Prior to its retirement in 2017, the NAPAF was set at 50%. The units in this station were commissioned between 1970 – 1975.

Therefore, CEA should ideally analyse and publish state-specific capacity credits for conventional generators considering these additional factors.

4. Determination of energy storage capacity credits should be linked to state-wise peak hour duration.

The discussion paper assigns a capacity credit for Battery Energy Storage Systems between the 0.5 – 1 and for PSP at 0.9-1. This assumes a 2-hour BESS in a grid whose daily peaks lasts for a duration of 4 hours and PSP having high storage duration. Since the availability of storage is energy limited, it is critical that the capacity credit of energy storage (BESS and PSP) is not the same for a 2/4/6/8 hour BESS or PSP system. DISCOMs have been procuring 1/2/4 and even 8 hour BESS systems and most planned PSP projects have an average of 6.3[3] hours of discharge/day. Further the recent GUVNL & SECI bids mandate 2 cycles/day for BESS system, thereby getting twice the energy in a day. Thus, the capacity credit calculation for energy storage needs to be more nuanced.

Firstly, the capacity credit of any storage technology should vary across states based on the duration of state peak demand as determined by SLDCs. Thus, if a SLDC declares its peak as 3 hours, then a 2 hour BESS could get a 0.75 CC (subject to availability) and a 4 hour BESS would get a CC of 1. If the number of cycles/day > 1, mandated as per the contract, then that too should be factored into the CC calculation. In the future, the CC for energy storage, esp. BESS could also factor in the location, i.e. considering Transmission availability. Finally, just like conventional generators, auxiliary consumption, and Depth of Discharge (for BESS) should be considered while determining capacity credits for energy storage.

[3] Based on analysis of 115 PSP projects from the MoEFCC Environmental Clearance database, the range for daily discharge is 5-11.6 hours/day.

5. Capacity Credit for VRE sources like wind and solar

The paper analyses the CC for VRE sources (wind & solar) for the top 10% hours and further separately for top 10% hours in solar and non-solar hours. Further it also analyses the same for critical days (135 days; i.e. 37% of the days) defined as those with medium-high demand and low-medium RE. The results for Solar and Wind are shown in the table 3 & 4.

Table 3: Capacity Credit for Solar during solar hours in top 10% demand hours and critical days methodology

Solar, during solar hours	Top 10% demand hours analysis	Critical Days analysis	Reduction in CC from top 10% to critical days analysis
State	Solar hours		
GUJARAT	0.56	0.46	18%
MAHARASHTRA	0.56	0.45	20%
KARNATAKA	0.54	0.46	15%
BIHAR	0.48	0.41	15%
CHHATTISGARH	0.57	0.44	23%
HIMACHAL PRADESH	0.49	0.37	24%
HARYANA	0.49	0.4	18%
KERALA	0.46	0.42	9%
MANIPUR	0.46	0.41	11%
MEGHALAYA	0.33	0.3	9%
MIZORAM	0.47	0.41	13%
NAGALAND	0.32	0.32	0%
DELHI	0.51	0.4	22%
ODISHA	0.48	0.4	17%
GOA	0.55	0.45	18%
ARUNACHAL PRADESH	0.25	0.29	-16%
PUNJAB	0.47	0.39	17%
RAJASTHAN	0.57	0.46	19%
JHARKHAND	0.57	0.43	25%
MADHYA PRADESH	0.54	0.43	20%
SIKKIM	0.35	0.31	11%
TELANGANA	0.55	0.43	22%
ANDHRA PRADESH	0.53	0.42	21%
TAMIL NADU	0.53	0.46	13%
TRIPURA	0.42	0.35	17%
UTTAR PRADESH	0.49	0.42	14%
UTTARAKHAND	0.57	0.46	19%
WEST BENGAL	0.51	0.42	18%
ASSAM	0.42	0.35	17%

Table 4: Capacity Credit for Wind during solar and non-solar hours in top 10% demand hours and critical days methodology

Wind Power	Critical Days analysis		Top 10% demand hours analysis		Reduction in CC from top 10% to critical days analysis	
State	Solar hours	Non-Solar Hours	Solar hours	Non-Solar Hours	Solar hours	Non-Solar Hours
KARNATAKA	0.09	0.17	0.103	0.28	13%	**39%**
TAMILNADU	0.08	0.07	0.126	0.28	37%	**75%**
ANDHRA PRADESH	0.09	0.14	0.087	0.32	-3%	**56%**
GUJARAT	0.13	0.21	0.129	0.25	-1%	**16%**
MADHYA PRADESH	0.08	0.19	0.098	0.23	18%	**17%**

As the paper notes, *'The capacity credit of Variable Renewable Energy (VRE) sources is significantly influenced by demand patterns, weather conditions, and environmental factors and is subject to change over time.'* Thus, this exercise will have to be done regularly and updated based on changing system characteristics.

In this context, the paper has noted that, *the median value is recommended instead of the mean or average, as the median is a better representation of resource generation, which is available 50% of the time during peak demand hours.'* CEA could also explore the possibility of considering the 75% percentile and share this analysis before deciding on the final value.

Finally, as suggested in the context for coincident peak analysis, CEA could consider another time dimension to evaluate CCs by additionally segregating between solar vs. non-solar hours and across monsoon vs. non-monsoon seasons, esp. given the seasonal variation in wind and the sharp reduction in CC of wind in non-solar hours. A final call on the CC for wind and solar could be based on comparing the CCs for critical days and CC for monsoon/non-monsoon seasons for solar and non-solar hours.

Table 5: Capacity Credit solar/non-solar hours and monsoon/non-monsoon seasons.

	Solar Hours	Non solar hours
Monsoon (June-Sep)		
Non Monsoon (Oct-May)		
Critical Days		

Further, the present methodology to determine CC is based on existing and past solar and wind generation profiles. Given the increasing trend of integrating trackers in solar projects, higher DC loading and new wind projects with much higher hub heights and rotor diameters, the profiles for newer solar and wind capacity is likely to be different from the past patterns. This should be reflected in the CC methodology. Similarly, it would be better if CEA can consider offshore wind as a separate technology and publish its capacity credit based on the available data from pilot projects or simulated data.

Finally, the first step of the methodology under Section 4.3.4 is stated as: *'Collect the demand profile and RE generation at the National and state level for the last 2-3 years.'* Our understanding of this section is that the demand data is at the National level while the RE generation data is at the State level. We request CEA to kindly confirm this for adequate clarity.

6. Consideration of transmission capacity and need for transmission resource adequacy in future exercises

The discussion paper stipulates that distribution utilities should contract firm capacity equivalent to the 80th percentile of the coincident peak in the top 5% of national demand during solar and non-solar hours. It notes that any demand in excess of firm contract capacity be met via electricity exchanges. However, presently there is no consideration of the availability of transmission capacity (as noted below) to import the deficit in supply from options such as electricity exchanges. Therefore, going forward, there is a need to take transmission capacity into consideration and carry out similar RA exercises for transmission adequacy as well.

> *Conventional approaches for calculating CC typically treat the power system as a single area without considering transfer constraints and the reliability of interconnectors. However, in multi-area power systems locational aspects are key to assessing trade-offs and synergies arising from transmission, storage, and RES in providing supply adequacy. In this paper, the capacity factor of generating sources has been considered on a standalone basis.*

7. Determine capacity credit of Demand Response technologies in future iterations.

As end-use electrification, smart meter roll-out & digitalization continues, there is an increase in the possibility of different loads which can alter their consumption patterns based on multiple parameters (E.g., price of electricity, time of day etc.). Going forward, RA studies should consider demand response technologies as a viable option to meet demand and assign capacity credits for such technologies appropriately.

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