Comments on the Staff Paper on Capacity Market for Electricity in India [1]

Context from the Staff Paper

The staff paper discusses three broad options for RA/capacity obligation procurement. **Option 1** proposes capacity-charge-only bidding, where the discom pays a discovered capacity charge and both the generator and discom participate in the Day-Ahead Market/Real-Time Market (DAM/RTM). To protect the discom's right over contracted capacity, the paper suggests that the discom's demand curve for such contracted capacity could be placed slightly above the price cap. The paper itself notes that this may not be optimal and could raise concerns about inflating the Market Clearing Price (MCP).

Option 2 proposes a more hybrid approach. The discom may invite bids based on total cost, including capacity charge and variable charge. The discom may have scheduling rights before the DAM window opens, while dispatch is still through the market. After market clearing, the discom and generator can settle the difference between the MCP and the contracted price outside the market.

The following comments focus on the methodology for estimating Net-CONE and explain why Option 2 may be preferable in the case of decentralized procurement. The comments also highlight the need to focus on flexibility market design and the formal definition of stress hours.

1. Challenges in Estimating Net-CONE under Competitive Power Markets

Net-CONE is not only a financial parameter. It is a system-level estimate. It depends on how much a new capacity resource is expected to earn from energy and ancillary-service markets over time. Those expected revenues depend on the future system-wide dispatch and market price formation, not merely on the load forecast of the individual discom that is procuring capacity. A simplified representation is:

Net CONE = Gross CONE - Expected Net Energy and Ancillary-Service Revenue

where:

Gross CONE = Annualized Capital Cost + Fixed O&M + Other Fixed Costs

and expected net market revenue is sum of market price and market quantity delivered by the seller/generator in the power markets. The difficult part is estimating prices in market and the quantity that the generator would be able to sell. **These values cannot be determined by an individual discom alone, as they depend on the overall power system dynamics. They are influenced by multiple interconnected factors, including demand across all regions, generator availability, renewable energy generation profiles, storage charging and discharging behavior, hydro conditions, fuel costs, transmission constraints, reserve scarcity, and market clearing mechanisms. In addition, factors such as future market price volatility, policy and regulatory uncertainties, carbon pricing**

[1] Dr. Himanshu Anand, Postdoctoral Researcher (IIT Kanpur) (Expertise: Power Market Analysis & Policy and Regulatory) and Dr. Bakul Kandpal, PhD (IIT Delhi), Postdoctoral Researcher (NTNU, Norway) (Expertise: Power System Optimization & Market Analysis)

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implications, estimation of future ancillary service revenues, and the impact of DSM charges also play a significant role in determining these values.

2. Limitations of Discom-Level Net-CONE Estimation

If each discom estimates Net-CONE independently, it may use only its own load forecast and procurement requirement. This is incomplete because a new generator's market revenue depends on the system-wide marginal price, not on the contracting discom's individual demand curve. The same generator may earn high revenue if the total system is capacity-short, but low revenue if several other discoms also procure new capacity or if renewable and storage buildout reduces market prices.

This creates a circularity problem:

- Net-CONE depends on expected energy-market revenue.
- Expected power market revenue depends on future market prices and dispatch.
- Future prices and dispatch depend on how much new capacity gets built.
- How much new capacity gets built depends on the capacity procurement mechanism and Net-CONE assumptions.

Therefore, a fragmented discom-level approach may produce inconsistent Net-CONE estimates. Some discoms may overestimate future market revenue and underpay capacity providers. Others may underestimate market revenue and overpay. The aggregate procurement outcome may also change future prices and invalidate the original assumptions.

3. Net-CONE should preferably be estimated by a central or system-level agency

If Net-CONE is to be used as the main benchmark for capacity remuneration, it should preferably be estimated by a central agency or pooled procurement agency. This agency could run a national, regional, or deliverability-zone-level capacity expansion and dispatch model using forecasted load, existing capacity, candidate new capacity, fuel prices, renewable profiles, storage costs, hydro constraints, reserve requirements, and transmission constraints.

The modelling approach could be similar in spirit to least-cost planning models such as GenX or other capacity expansion and dispatch models. The objective would not be to mechanically replace the market, but to provide a transparent and internally consistent estimate of future hourly or sub-hourly dispatch and prices. Based on these simulated prices and dispatch patterns, the agency could estimate likely market revenues for different new resources and derive Net-CONE values.

The central agency would be better placed to see the global optimization problem than individual discoms. It would see the combined future load of all participating discoms, the existing and planned generation fleet, storage operation, transmission constraints, and the interactions across regions. This is important because a discom acting alone sees only a part of the problem, while Net-CONE depends on the full market outcome.

2. If procurement remains decentralized, Option 2 with CfD-style settlement and periodic revision is preferable to Option 1

2.1 Core point

If capacity procurement remains decentralized at the individual discom level, then a pure Net-CONE-based capacity-only contract may be difficult to implement reliably. In such a case, Option 2 of the staff paper appears more practical than Option 1. Option 2 allows a total-cost contract and an outside-market settlement between the MCP and the contracted price. This is similar to a contract-for-difference (CfD) structure and can reduce the need for artificial above-price-cap demand bidding.

2.2 Why Option 1 could be problematic

Option 1 tries to protect the contracting discom's right over capacity by placing the discom's demand curve slightly above the price cap for the contracted quantity. The discom would not pay its own bid price; it would pay the uniform MCP. However, by bidding above the price cap, the discom may make demand artificially inelastic and may cause a higher-cost resource to clear. This may raise MCP for the whole market, including the contracting discom itself.

The discom's total cost under Option 1 can be represented as:

Total Cost = Capacity Charge + MCP x Energy Purchased

If the above-price-cap demand bid increases MCP, the discom may end up paying both the capacity charge and a higher energy-market price. Therefore, the mechanism intended to protect the discom may increase its procurement cost.

The staff paper suggests that capacity holders may be required to bid as price takers during peak/stress hours. This may reduce the risk of MCP inflation, but it does not eliminate the underlying design problem. The energy-market demand curve is being used to solve a capacity-rights and free-rider problem.

2.3 How a CfD-style settlement works under Option 2

Under Option 2, the discom and generator can agree on a contracted price or total cost benchmark, while actual dispatch still occurs through the market. The generator sells into DAM/RTM and receives MCP. The discom buys from DAM/RTM and pays MCP. The difference between MCP in the market and the contracted price is settled outside the market.

This preserves market-based dispatch while protecting both parties from price risk. It also avoids the need to place the discom's demand bid above the price cap.

2.4 Need for periodic price revision or reopener provisions

A long-term capacity or CfD-style contract should not lock in an incorrect Net-CONE or revenue assumption for 10 to 15 years without adjustment. Future market revenue can change due to demand growth, renewable penetration, storage deployment, fuel-price changes, hydro availability, transmission expansion, carbon or environmental policy, and market rule changes.

Therefore, if a decentralized Option 2-type structure is adopted, the contract should include periodic revision or reopener provisions. These provisions could be similar in principle to indexation or periodic benchmark adjustment clauses used in long-term power and financial hedge contracts. The goal is not to create a full cost-plus pass-through mechanism, but to allow a transparent and bounded recalibration when actual market conditions differ materially from the original assumptions.

Possible revision triggers may include:

- *a scheduled review every year or every three years;*
- *material change in fuel price or variable cost index;*
- *material deviation between assumed and actual market revenue;*
- *change in market price cap or market rules;*
- *major change in capacity accreditation or availability requirements;*
- *change in transmission deliverability that materially affects dispatch or revenue;*
- *change in reserve or ancillary-service obligations.*

The revision mechanism should be rule-based and should include caps/floors or sharing factors so that both buyer and seller retain incentives for efficient operation and market participation. For example, only a part of the deviation between expected and actual market revenue could be adjusted, or revisions could be limited to predefined cost indices and market-rule changes.

2.5 Why Option 2 may be more suitable during transition

Option 2 may be more suitable for India during a transition from traditional PPAs to market-linked capacity remuneration because it preserves some financial certainty for both discoms and generators while still moving operational dispatch toward DAM/RTM. It also avoids the most problematic feature of Option 1: using above-price-cap demand bids to guarantee the discom's right over contracted capacity.

In this approach, buyer protection is achieved through financial settlement rather than through artificial energy-market bidding. The free-rider issue can be addressed separately through mandatory RA compliance, capacity credit allocation, and residual central procurement, instead of being solved indirectly through inflated demand bids in the energy market.

2.6 Avoiding artificial market-clearing arrangements: Option 2 should clearly distinguish between physical assurance and financial hedging

A further clarification is required in Option 2. The proposed design should not rely on artificial DAM/RTM bidding arrangements to make a bilateral capacity contract behave like a physical contract. If the discom has paid for a specific capacity resource and needs that capacity during urgent or stress hours, then trying to force both the buyer and the seller to clear through anonymous DAM/RTM bidding may create avoidable uncertainty.

In an anonymous market-clearing framework, the discom may clear as a buyer and the generator may clear as a seller, but this does not necessarily mean that the discom has physically received energy from that specific contracted generator. Even if both parties bid as price takers, the result is still a pooled market outcome unless the market design explicitly creates linked buyer-seller bids or a capacity-backed scheduling tag. Therefore, using price-taking bids or above price-cap demand bids is only essentially a bilateral exchange of power between discom and the generator through the disguise of the market, but will not reflect how ideal market dynamics should work.

If the intent of Option 2 is to give the discom physical assurance over the contracted capacity, then the modified design is to treat the contract as a physical call-option or capacity backed scheduling right. Under such a structure, the discom may have the right to schedule up to the contracted capacity from the generator before the DAM gate closure or during predefined NLDC declared stress conditions. The quantity called by the discom should be settled bilaterally at the contracted energy charge or contracted total-cost benchmark. Only the uncalled capacity should be released into DAM/RTM.

Recommendation: The main concern is that Net-CONE is difficult to estimate correctly if capacity procurement is done separately by individual discoms. Net-CONE depends on expected future energy-market and ancillary-service revenues. These revenues are not determined by one discom's demand alone; they are determined by the entire power system, including future demand, renewable generation, storage operation, fuel prices, transmission constraints, scarcity hours, and market clearing prices.

The preferred design depends on whether India wants capacity procurement to remain decentralized at the discom level or move toward a central/pool-based resource adequacy mechanism.

If Net-CONE is to be the primary basis for capacity remuneration, centralized or pooled procurement is more suitable. A central agency can run a system-wide capacity expansion and dispatch model, estimate future prices and revenues, and derive a credible Net-CONE. This is more consistent with the system-level nature of Net-CONE.

If procurement remains decentralized, then Option 2 with CfD-style settlement, periodic revision, and clearly defined contract terms is preferable to Option 1. The above-price-cap demand bidding mechanism in Option 1 should be avoided or used only after detailed market simulations demonstrate that it does not materially inflate MCP.

In either case, Net-CONE should be transparent, scenario-based, periodically updated, and supported by strong RA compliance, capacity credit allocation, capacity accreditation, transmission deliverability assessment, and stress-hour performance obligations.

4. Strategic Reserve Planning and Strengthening of the Resource Adequacy Framework

India has already established a framework for reserve procurement through the Ancillary Services Regulations, which provide for the procurement of Secondary Reserve Ancillary Services (SRAS) and Tertiary Reserve Ancillary Services (TRAS) through both day-ahead and real-time mechanisms. However, with increasing renewable energy penetration and growing system flexibility requirements, there may be a need to further strengthen reserve adequacy planning and develop a more structured reserve capacity framework.

Key Concerns

- Resource Adequacy (RA) obligations are still evolving and are not yet fully embedded across all states and distribution utilities, resulting in varying levels of contracted reserves and preparedness.
- Limited reserve availability may increasingly pose risks to system reliability, particularly under high renewable energy penetration scenarios.
- During solar-rich periods, net demand reduces significantly and thermal generating units often operate at or near their Minimum Technical Limit (MTL), leaving limited operating reserves available to manage contingencies, renewable variability, forecast errors, and sudden demand fluctuations.

- As renewable penetration increases, reserve requirements are expected to grow, making advance reserve planning and procurement increasingly important.

Suggestions

- The current RA framework may be further strengthened by incorporating explicit reserve adequacy obligations, **particularly for states whose peak demand coincides with periods of national system stress**.
- A comprehensive assessment of seasonal reserve requirements may be undertaken **across summer, winter, monsoon, and high renewable generation periods to determine appropriate levels of operating reserves and strategic reserves**.
- Detailed market and system studies may be conducted to evaluate the feasibility of a transparent, nationally coordinated reserve capacity market framework that complements the existing ancillary services market.
- The **role of intra-state generating stations in reserve provision** may be enhanced. Instead of relying solely on reserve procurement coordinated at the national level, mechanisms may be explored to facilitate active participation of intra-state generators in reserve and ancillary service markets.
- Greater alignment between Resource Adequacy planning, ancillary service procurement, reserve management, and flexibility assessment may help optimize reserve availability at both state and national levels.
- **Capacity building initiatives may be undertaken at SLDCs, state utilities, and distribution companies to strengthen reserve assessment capabilities, forecasting practices, and operational planning processes.**
- **Investment in advanced analytical tools, forecasting platforms, reserve estimation methodologies, and decision-support systems may be encouraged at the state level.**
- Similar to the **evolution of SCED and RRAS co-optimization frameworks at the inter-state level, pilot projects may be undertaken to evaluate reserve co-optimization and flexibility procurement mechanisms at the intra-state level**.

5. Transition Framework for Resource Adequacy and Capacity Market Development

The Resource Adequacy (RA) framework should focus not only on short-term compliance requirements but also on achieving an optimum long-term system-level solution for reliability, flexibility, and cost efficiency. At present, RA obligations are primarily being considered for a limited horizon of 2–3 years, which raises an important concern regarding whether discoms would be willing to enter into long-term capacity tie-ups under such uncertainty.

Before moving toward, the implementation of a capacity market mechanism, several foundational aspects may require further evaluation and strengthening. The transition should ideally follow a phased and coordinated approach, including:

- Implementation of SCED at the state/discom level

- Comprehensive RA modelling exercises using different optimization and market scenarios
- Full compliance with RA obligations by all states and implementation of RA guidelines
- Integration and coupling of short-term market platforms such as TAM, DEEP, and other procurement mechanisms to improve market liquidity
- Alignment of state-level planning with national-level optimized planning targets up to 2035
- Assessment of the transition toward centralized dispatch mechanisms
- Detailed comparative analysis of centralized versus decentralized procurement frameworks, considering not only short-term cost optimization but also long-term investment signals and system reliability

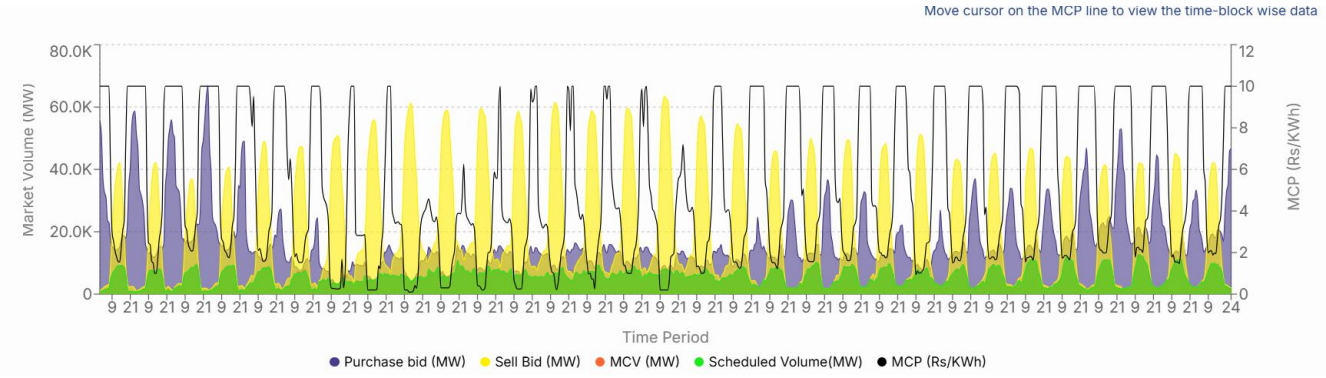
Otherwise, discoms may continue focusing primarily on meeting immediate demand obligations through long-term PPAs, resulting in excess contracted thermal capacity at the national level for limited peak demand requirements. At the same time, increasing renewable energy capacity additions, particularly rapid solar expansion combined with relatively slower wind capacity growth, may further widen the day-night balancing challenge. This could lead to additional storage or thermal power procurement requirements to manage non-solar hours and maintain system reliability. In this context, greater emphasis may also be required on:

- Demand response programs
- Flexibility markets
- Energy storage integration
- Reserve management mechanisms
- Efficient utilization of existing generation resources

A carefully sequenced transition pathway would therefore be essential to ensure that the RA framework supports long-term market efficiency, investment adequacy, renewable integration, and overall grid reliability.

6. Assessment of Price Caps and Long-Term Investment Signals in the Indian Power Market

The current trend observed in Indian power exchanges indicates that during evening, night, and early morning hours, market prices in certain periods consistently touch the price cap of ₹10/kWh in DAM, while buyer participation and Market Clearing Volume (MCV), particularly in HPDAM, remain extremely low or even negligible. This raises important questions regarding the existing power market design and the effectiveness of current price discovery mechanisms.



Source: IEX

The prevailing price cap of ₹10/kWh may not provide adequate long-term investment signals for future capacity addition and system flexibility resources. For instance, during the initial phase of large-scale battery energy storage deployment, developers may realize significant returns due to scarcity pricing. However, as storage penetration increases, market prices are expected to moderate, thereby improving overall system flexibility, reliability, reserve adequacy, and grid security. Such market evolution is a natural characteristic of competitive electricity markets and may support efficient long-term resource optimization.

In this context, there may be a need for a deeper assessment of medium- to long-term investment signals within the competitive power market framework, rather than relying excessively on artificial price caps. Additionally, regulatory restrictions on high-price power procurement in certain cases (e.g., around ₹8–10/kWh) may also influence market participation, liquidity, and price formation, particularly during stressed system conditions. A balanced approach may therefore be required to ensure both consumer protection and adequate market-based incentives for future flexible and reliable capacity development.

7. Need for Defining and Identification of Stress Hours in the Indian Power Market

The discussion paper may further elaborate the distinction between **stress hours**, **peak demand hours**, and **solar/non-solar operating periods**, as these concepts are increasingly important under high renewable energy (RE) penetration scenarios. Internationally, different jurisdictions define stress events based on parameters such as reserve adequacy, supply-demand imbalance, congestion, extreme weather conditions, or market price signals. In the Indian context, there may be a need to formally define "stress hours" under the IEGC or related regulatory frameworks. Such a definition could consider factors including:

- Low reserve margin conditions
- Persistent congestion
- High renewable variability
- Frequency deviations
- Market prices touching or approaching the price cap
- Significant over-drawal or system imbalance conditions

An assessment of the number and duration of such stress blocks observed in recent years may also help in identifying operational trends and future flexibility requirements. Further, stress hours may be linked more closely to reliability and reserve adequacy mechanisms, demand response activation, and ancillary service requirements, rather than being solely associated with capacity market constructs. In parallel, State Load Dispatch Centres (SLDCs) may also need to strengthen short-term Resource Adequacy (RA) assessments, particularly during critical demand days, periods of high renewable energy generation, low reserve margin conditions, and congestion or ramping stress scenarios, thereby enabling better preparedness and enhanced grid security under evolving power system conditions.

8. Flexibility Market Design

With the increasing focus on Renewable Energy (RE) targets and Renewable Consumption Obligations (RCO), the Indian power system is expected to experience significantly higher renewable energy penetration in the coming years. As indicated in the figure, high solar generation availability during morning hours may further intensify market imbalances and operational stress on thermal power plants (TPPs), particularly due to frequent shutdowns and low-load operation requirements. In this context, future market design should increasingly focus on flexibility-related aspects such as:

- Minimum Technical Limit (MTL)
- Ramping capability
- Hot/Warm/Cold startup capability and associated operational constraints

Several regulatory initiatives have already been undertaken to improve thermal fleet flexibility, particularly:

- Reduction of MTL up to 40%
- Compensation mechanisms for flexible operation

However, an important question remains: Are these flexibility initiatives primarily supporting secure system operation or providing flexibility during down reserve requirement? There is a need to develop a comprehensive long-term flexibility planning framework and assess how future market design can incentivize flexibility services in the power market. Such a framework would support:

- Better reserve management
- Improved renewable integration
- Enhanced grid reliability and discipline
- Efficient utilization of thermal and flexible generation resources

Key Areas for Flexibility Assessment

Flexibility Level	Key Assessment Area	Key Considerations
Level 1: MTL Reduction	Low-Load Operational Flexibility	• Ability of generators to operate reliably at lower Technical Minimum Load (MTL) levels
		• Impact on reserve availability and renewable energy integration
		• Reduction in renewable energy curtailment and improved system balancing
Level 2: Ramping Capability	Ramp-Up / Ramp-Down Flexibility	• Capability to respond to rapid changes in demand and renewable generation
		• Faster ramp-up and ramp-down performance
		• Assessment of ramping adequacy during morning and evening peak ramp periods
Level 3: Startup Flexibility	Hot, Warm, and Cold Start Capability	• Optimization of startup and shutdown cycles
		• Evaluation of startup time and operational costs
		• Impact on plant life degradation and maintenance requirements
		• Expected availability and flexibility over plant life extension periods

A structured and enforceable flexibility framework may be developed for generators participating in the Indian power market, with consideration for introducing a dedicated flexibility market or ancillary flexibility mechanism aligned with future power system requirements. Market products may progressively evolve to explicitly value flexibility attributes such as fast ramping capability, startup

flexibility, reserve provision, and low-load operation capability. In addition, flexibility-related parameters should be more comprehensively integrated into Resource Adequacy (RA) planning studies. Such measures can significantly contribute toward improving grid discipline, enhancing system reliability, enabling higher renewable energy integration, and supporting efficient market operations under high renewable energy (RE) scenarios.