Comments and Suggestions on the Staff paper on Capacity Markets for Electricity in India

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At the outset, we would like to commend the Commission's efforts in documenting and sharing international experience on capacity markets, both through this paper and the series of workshops it has organised. These discussions help us understand the contexts in which capacity markets have evolved and their underlying design principles, as well as their relevance to India in light of our existing challenges and the prevailing regulatory, legal and sectoral landscape.

The paper discusses three potential use cases for capacity markets:
Use Case 1: Meeting Resource Adequacy (RA) Obligations
Use Case 2: Meeting Reserve Requirements
Use Case 3: Procuring Short-Term Power from Existing Capacity

For meeting reserve requirements (Use Case 2), we see merit in exploring capacity markets, as the centralised procurement of reserve capacity to meet system requirements seems optimal. However, there is lack of clarity in implementation aspects which are detailed in Section 1 of this submission. For short-term procurement (Use Case 3), we recognise the need for transparent platforms and standardised contracts to enable competitive, market-based procurement. However, given the short durations involved, the DISCOM should ideally retain scheduling rights; accordingly, a better-structured and integrated market, rather than a capacity market, is the need of the hour. Some proposals and suggestions in this regard are detailed in Section 2 of this submission.

For Use Case 1 — long-term procurement to meet RA requirements — we do not see merit in pursuing the proposed capacity market at present. With India's demand doubling each decade and storage investments scaling rapidly, DAM prices will evolve substantially over a 15-year contract term, making long-term assessment of energy-market revenue uncertain. Generators facing this uncertainty will load cost recovery onto the capacity bid, producing inflated Net CONE outcomes in Option 1 and inflated total prices with high BCS settlements in Option 2. The combination of capacity-loaded bidding and large hedged volumes will, in turn, distort MCP formation across the rest of the market, weakening price signals during peak and stress periods, and removing incentives for thermal flexibilisation such as technical minimum reduction and ramp-rate improvement. The paper also leaves unaddressed three consequential risks for DISCOMs: the landed-cost implications of ISTS transmission charges, area-price divergence with congestion, and the working-capital strain that upfront exchange-based payment cycles will impose. These concerns are detailed in Section 3.

A major rationale for Use Case 1, as with the earlier MBED proposals advanced by the CERC and the Ministry of Power, is the optimal utilisation of un-requisitioned capacity. However, before contracting all long-term capacity through capacity markets to meet this objective, we would suggest measures to ensure compliance with Rule 9 of the LPS Rules, which mandates the sale

of un-requisitioned power in the existing DAM and RTM. This is detailed in Section 4 of this submission.

1 Introduce capacity markets for reserves

Staff paper proposal: NLDC conduct two separate annual auctions, for secondary and tertiary reserves, based on the national shortfall identified after DISCOM procurement. The capacity is contracted for one year, with a bid cap at 10% above an NLDC-determined Net CONE. The generator receives the cleared capacity charge in all three scenarios: when requisitioned and dispatched (with a quoted energy charge), when requisitioned but not dispatched (with a commitment/holding charge), and when not requisitioned at all (with the freedom to sell in DAM/RTM at MCP). A penalty of 1.5×(capacity charge + AS price) applies for failure to participate in the AS market. Because contracts are annual, the design implicitly assumes existing capacity will be repurposed to provide reserves and no new build is envisaged.

While we agree with the broad proposal of the paper, the following aspects remain unclear:

- **Basis for Net CONE determination by NLDC for fixing cap**: NLDC is to set Net CONE based on "market analysis/study," but no methodology, input data, periodicity of revision, or appeal mechanism is specified. This is crucial to ensure significant participation of serious players in a cost-competitive manner.
- **Manner for energy charge quotes**: The paper requires bidders to quote an energy/compensation charge but does not subject it to caps or validation, and does not use it as a selection criterion. Bidders therefore have a strategic incentive to bid low on the capacity charge (to win the auction) and quote high on the energy charge (which is socialised through the DSM and AS pool when paid). The energy charge should be capped, declared in advance, or incorporated into a combined selection criterion to enable genuine competitive price discovery.
- **Commitment charge**: The paper states the commitment/holding charge will be "determined by the Commission" but provides no methodology. The methodology needs to be specified before the auction is workable.

We suggest that NLDC issue a detailed design paper for public consultation addressing these aspects. CERC should consider the NLDC proposal and stakeholder comments before issuing an order on the contours of the capacity market for reserves.

2 Double-sided auctions over standard slots for weekly, monthly contracts

Staff paper proposal: Introduction of capacity markets for centralised short term procurement for all DISCOMs to meet short-term requirements. The proposal is to have centralised capacity auctions every month for three months ahead. In one possible market design option, DISCOMs can schedule capacity on a day ahead basis using DAM. In another, DISCOMs should ensure scheduling before commencement of DAM, failing which the sellers sells power on DAM and DISCOM continues to pay the capacity charge.

We strongly support the staff paper's intent to redesign platforms/ contracts for short-term procurement for India's DISCOMs. LDC, ADSS contracts on TAM are non-standardised and fragmented and thus will not be competitive. Further, we believe that 10 years after its launch, the DEEP platform and e-auction approach for procurement has outgrown its utility. DISCOMs have few options for procurement especially for peak contracts with poor participation by generators. Further it is unclear if all contracts lead to actual delivery.

However, instead of launching yet another capacity market linked contract, it is suggested that present LDC, ADSS and DEEP e-auction mechanisms are replaced by a standard contract offered on the power exchanges. It is suggested that:

a. Buyers and sellers offer bids in a Uniform Price Step Auction with standard trading sessions. After two years, the clearing mechanism should be double sided closed auction as in DAM. Standard trading sessions and pre-specified timelines should be retained.
b. The contract is offered for weekly, fortnightly and monthly durations on a month-ahead and up to three month ahead basis.
c. To ensure liquidity, only "block-bids" for only 6 time-slots should be allowed on these contracts as detailed in Table 1.

Table 1: Pre-specified Slot/ Block bid durations for short term contracts

Pre-specified Slot/ Block bid durations	Time periods
RTC	00:00-24:00
Solar	06:00-18:00
Morning	06:00-09:00
Day	09:00-18:00
Non-Solar	18:00-06:00
Evening	18:00-00:00

This is similar to the pre-specified time slots for TAM/ HP-TAM/ GTAM (Hydro) approved by CERC in order dated 21st May 2026[1]. The slots have overlaps but separate bids need to be placed for each slot.

d. Provisions for default, deviation from schedule, payment timelines etc can be as per the MoP's short-term bidding guidelines, 2016 with suitable and necessary amendments as required.
e. DEEP platform, ADSS contracts on exchanges as well as all LDC contracts should be discontinued to prevent fragmentation.
f. Such short-term markets need not have a price ceiling for bids. DISCOMs can get regulatory approval to exceed cap on short-term power purchase if necessary while participating in bids.

We believe that such an approach would lead to competitive power procurement, improved utilisation of un-requisitioned capacity, increased liquidity in TAM contracts and improve transparency and accountability of short-term trades.

[1] https://cercind.gov.in/2026/Orders/674-RC-2025.pdf

With trajectory of solar and storage and less than 2 years' time period for commissioning, capacity to respond to demand and price signals in this market can come up quickly and this liquidity challenges in this market can also be addressed over time.

3 Reconsider RA Obligation Capacity markets due to risks and uncertainties

Staff paper proposal: DISCOMs or a central agency acting on their behalf procure power for a period of 10 to 15 years. Unlike standard power procurement contracts, DISCOMs relinquish their right to schedule the contracted capacity. Instead, all DISCOMs and generators bid their required and available capacity, respectively, into the Day Ahead Market, and capacity is scheduled to the DISCOM from the pool of cleared generators, irrespective of contract, on the basis of the market clearing price (MCP). The paper sets out two alternatives for what is bid to contract the capacity itself. Under the capacity bid alternative, generators bid only a capacity charge for the contract duration, and recover the rest of their revenue separately through the Day Ahead Market. Under the per-unit bid alternative, generators instead bid a full per-unit price meant to cover their total cost, payable by the contracting DISCOM. The difference between the generator's bid per-unit rate and the 15 minute block-wise cleared MCP is transferred to the contracting DISCOM through Bilateral Contract Settlement (BCS), so the DISCOM effectively gets the per-unit price it contracted for. To ensure DISCOMs requirement is scheduled in the market, the DISCOM demand will be drawn above the price cap. Further to mitigate volume risk in critical periods, capacity providers are obligated to bid and clear during stress periods, failing which they pay a penalty of 1.5 times the discovered capacity charge.

Some areas where there is a lack of clarity in the proposal, as well as some potential risks and implementation challenges with the proposed approach, are detailed below for discussion:

Potential scale of capacity-market volumes relative to existing markets

State RA plans prepared by CEA indicate that states will need approximately 99 GW of additional coal capacity by 2035. Of this, 46.8 GW is neither under construction nor planned, and could potentially be contracted through RA capacity markets. Even if only 30% of this unplanned capacity is procured through the proposed capacity market, at a conservative 65% PLF assumption it corresponds to approximately 79 BU of annual energy. For context, the total volume transacted across all three exchanges in the Day-Ahead Market (DAM) was only 63 BU in FY26; assuming 5% annual growth, the DAM would reach approximately 90 BU by 2035.

On this basis, even a 30% routing of the unplanned coal capacity through capacity markets would account for approximately 45% of total transacted volume in the DAM in that year. At this scale, capacity-market-linked bids would no longer be marginal participants in the DAM — they would set the market clearing price during peak and stress periods rather than respond to it, shaping how the rest of the market behaves. Given this scale and the 15-year lock-in, five major risks warrant detailed deliberation, alongside several aspects of the proposal that are unclear or not addressed in the paper

Risk 1: The discovered capacity charge in Option 1 and total price in Option 2 are likely to be high

In Option 1, generators are expected to bid capacity charges that reflect the cost recovery they require *net of* expected revenue from energy markets over a 15 year period. In Option 2, they are expected to bid total cost with a BCS to hedge daily bids. The proposed framework creates

structural incentives for generators to load most of their cost recovery onto the capacity bid rather than the energy charge in Option 1. In Option 2, it would also lead to high total price discovery. Two aspects drive this **Net CONE inflation**:

a. **Uncertainty over future energy-market revenue***:* The design relies on generators forming a stable view of energy-market revenue over a 15-year horizon — which the current market does not support given thin liquidity and a structural trend towards downward movement of prices. Over time, solar will continue to depress day time prices and influx of storage assets will flatten price peaks. A rational bidder, especially with thermal capacity facing this trajectory will assume low and uncertain energy-market recovery, and will accordingly shift the bulk of cost recovery into the certain capacity payment. Alternatively in Option 2, generators would all bid high total cost in the auction and perhaps bid low in the energy market to assure scheduling, relying on BCS for recovery.

b. **15-year contract structure relative to existing 25-year PPAs***:* Amortising the same capex over 15 years rather than 25 years raises the annualised capacity charge requirement and total cost. The DISCOM thus funds the build-out of the asset through the capacity payment but foregoes scheduling rights during the contract and has no claim on capacity beyond year 15. Even with recent 25-year TBCB contracts for coal, we see that about 66% to 70% of the cost is approved by SERCs to be recovered through capacity charges (Table 2). As shown in Table 2, the energy charge discovered in TBCB tenders since FY24 is less than Rs. 2/unit for 82% of the 17.9 GW contracted. Such a bidding strategy lowers the variable bid, which dispatches the plant early in merit order. There is little reason to expect Net CONE bids in the proposed capacity market to behave differently, especially given uncertainties in market prices.

Table 2: Recently discovered tariffs for coal thermal capacity under TBCB

State	Capacity Awarded (MW)	Fixed Charge (Rs. /Unit)	Energy Charge (Rs. / Unit)	Total Charge (Rs. / Unit)	FC % of total tariff
Bihar	2400	4.17	1.91	6.08	69%
Kerala	300	4.03	1.73	5.76	70%
Madhya Pradesh	4000	4.22 – 4.30	1.54 – 1.61	5.81 - 5.38	70%
Maharashtra	3200	3.67	1.72	5.39	68%
Uttar Pradesh	1600	3.73	1.66	5.39	69%
Assam	3200	4.16	2.14	6.30	66%
West Bengal	1600	4.06	1.75	5.81	70%
	1600	3.60	1.85	5.45	66%

Source: PEG compilation from tariff adoption orders for various thermal PPAs issued by SERCs

c. **Absence of price caps:** For the capacity bids, no price caps are proposed which could have mitigated net-CONE inflation to some extent. However setting price caps, especially for technology-agnostic bids, would be challenging and could also influence bidding behaviour adversely. Thus, it is unclear, what mitigation measures can be evolved to address this inherent risk.

Risk 2: Skewed bidding behaviour could distort prices and increase DISCOM volume risks

With capacity payments or BCS hedges, sellers' bidding behaviour will be governed by different considerations. Since DAM bids determine whether the capacity is dispatched, generators with

available capacity will bid low to guarantee clearing and dispatch. When availability is constrained — particularly in non-peak hours when the 1.5× peak-hour clearance mandate does not apply — they could bid substantially high with the intent of not clearing, and therefore not being dispatched.

Thus, in a relatively thin market with large capacity-linked bids, solar-hour MCPs could be higher than expected if hedged thermal capacity strategically bids high — for instance during planned maintenance windows in those hours. Peak-hour MCPs could trend lower over time as generators bid low during stress periods to ensure clearing and avoid the 1.5× capacity-charge penalty. The market would therefore be less reflective of system marginal cost.

Therefore, generators whose revenue is governed by capacity contracts rather than dispatch performance lose the incentive to invest in technical minimum reduction, ramp-rate improvement, and other thermal flexibilisation measures. This undermines wider policy goals around efficient system operation and the grid integration of renewable energy.

For consumers, distorted MCPs would disincentivise time-of-day tariff adoption, weaken the case for market-linked demand-flexibility programmes, and limit open access participation by introducing price uncertainty.

One could argue that PPAs are also out-of-market hedges yet do not distort spot prices. This is true, but PPAs differ structurally from the proposed capacity contracts: scheduling under PPAs is governed by DISCOM instructions rather than market outcomes, and only marginal volumes from PPA-contracted capacity reach the DAM today.

The DAM is also not exclusively composed of capacity-linked bids. In any given block where total buy volumes exceed sell volumes, the DISCOM's buy bid may fail to clear. To manage this, DISCOMs, most of whom are yet to demonstrate proficiency as traders, may bid higher than necessary to ensure clearance. **The paper's proposed remedy is "drawing the demand curve of the contracting buyer at a price slightly above the price cap." This proposal is asserted in a single sentence, with no additional details so the import is unclear.** While such a work-around raises the clearing price. Further, once generators understand that DISCOM bids are administratively positioned above the price cap to guarantee clearance, they have every incentive to raise their own bids, confident that the design will clear them. This will raise MCP further.

In Option 2, the BCS may shield the contracting DISCOM from this MCP inflation. In Option 1, however, DISCOMs pay MCP directly for energy beyond the capacity contract and are therefore exposed to the higher prices. In such a case, bid screening is not a practical remedy as it would require validation of technical parameters for Section 63 projects, where such information is not required to be disclosed to regulators. In both Option 1 and 2, the resulting MCP distortion affects all non-capacity-market participants, not just the contracted parties. Therefore, unless workable mitigation measures are identified, capacity markets should not be introduced.

Risk 3: Serious limitations on market evolution

For sellers, the value of a capacity contract rests on the stability of the market design through which their future revenue is recovered. Any change to that market design during the 15-year contract term — whether a revision to price ceilings, the introduction of new bid orders or

contracts, changes to bidding timelines, changes to pre- and post-processing rules, changes to the price-discovery algorithm, or the introduction of new bid areas — would alter their revenue and profitability and could plausibly be invoked as a Change in Law claim. This is a substantial risk for participating DISCOMs. For India's evolving electricity market, a 15-year capacity contract anchored in the current market design effectively locks regulators and power exchanges out of this evolution. Compounding this, the risk of non-clearance and inflated MCPs due to bidding behaviour from capacity contract hedged buyers and sellers will deter other buyers and sellers from participating in the DAM.

Risk 4: Transmission price, congestion and landed cost risk

For DISCOMs participating in the proposed capacity market, even though contracted capacity is bid into the spot market, market clearing may dispatch a different generator. If the cleared generator is on the ISTS grid or the InSTS grid of another state, the DISCOM's landed cost could exceed the cost of running a backed-down existing intra-state contracted generator. The market-based dispatch in this case does not produce the most cost-optimal outcome. The risk is non-trivial: ISTS charges are projected to rise 10–15% per annum, widening the gap over the contract term. The same problem manifests through congestion management. As congestion increases and Area Clearing Prices will diverge, particularly in newer bid areas. Thus, exchange-based scheduling may dispatch capacity at a price that is uncompetitive against under-utilised intra-state options the DISCOM has already contracted. This risk is neither discussed nor quantified in the paper and no mitigation measures are detailed.

Risk 5: Cash flow challenges due to exchange linked procurement

Any trades on DAM would require upfront payment by DISCOMs. Thus, the payment schedules are much tighter than existing power purchase contracts which allow for payments within 45 days. In addition, in case of BCS, the difference between MCP and contract price needs to be transferred by generator to the DISCOM. Delays in this transaction also affect DISCOMs working capital requirement. Most DISCOMs have serious working capital borrowing (WCB) challenges with WCB as high as 40% to 80% of total borrowing. Such payment schedules would further strain working capital position. No measures to address this risk are detailed in the paper.

Lack of clarity on several aspects

a. What would be the frequency of capacity market auctions? Would the approval of regulator be needed to initiate auctions or is it at the discretion of the DISCOM?
b. Would it be for select capacity requirements or would all new capacity requirements need to be met through such auctions?
c. How would technology-agnostic auctions be designed? Present design heavily favours dispatchable capacities with two-part tariffs? Would it need to be different if solar+ storage is also envisaged as a participant?
d. How would Net CONE bids be evaluated? Do they need to be approved by appropriate ERC? Would separate bidding guidelines be required for capacity market auctions?
e. Is there a legal opinion that BCS is not classified as a derivative? This needs to be shared, discussed and settled before the launch of capacity markets.
f. What changes are needed in the pre and post bid processing rules as well as the algorithm to place DISCOM demand above price cap?

g. Can buyers and sellers in capacity markets place through all available bid orders?
h. If DISCOMs are unable to pay contracted generators on time and GNA access is restricted as per LPS, would they also lose access to capacity markets? In such a case can seller sell power in the market and what are the contractual and legal complications?
i. How much RA shortfall is needed by a DISCOM to trigger centralised procurement on long term basis? Will the agency be the same as NLDC which is tasked with capacity sharing auctions in case of short-falls for ST-NRAP? If the agency is different, which agency will it be? Will the ST-NRAP capacity auctions and long-term RA-based centralised capacity markets have parallel timelines or not?

Given the risks, uncertainties, and lack of clarity identified above, we urge that capacity markets not be considered until conditions in both the market and the wider system have matured materially. On the market side, power exchange volumes need to rise to at least 25% of total electricity consumption, market contracts and price-discovery procedures need to evolve and innovate, and open access consumers need to participate meaningfully in the exchanges. On the system side, greater clarity is needed on transmission-optimised planning and capacity siting, on the trajectory of RE and storage build-out, on credible flexibilisation pathways for thermal capacity, and on the congestion patterns that will emerge once each state is designated a bid area. Until these conditions improve, locking in 15-year contracts at this scale risks crystallising design choices that will prove ill-suited to the system as it actually evolves.

4 Immediately implementable measures to improve utilisation of contracted capacity

The major rationale for the introduction of capacity markets, especially long-term capacity markets, is to move towards centralised, market-based scheduling and dispatch for better utilisation of contracted capacity, especially thermal. We recognise that the underutilisation of available capacity contracted by DISCOMs that remains unscheduled is inefficient, and that measures to address this are necessary. **Instead of a centralised capacity market, we propose that sufficient incentives and penalties be put in place to operationalise the approach in Rule 9 of the Late Payment Surcharge (LPS) Rules.**

Presently, the Rule 9 (1) rules states that:

- DISCOM shall intimate schedule for each contracted generator two hours before bid closure in DAM.
- If DISCOMs fail to intimate schedule, generator shall offer the un-requisitioned capacity in DAM and subsequently RTM.
- Such URS shall also include capacity available against the declared capacity of the unit under shut down
- If generator fails to offer such URS, they would lose their right to claim fixed charge recovery in lieu of the URS.

However, the rules also cap generator bids in the DAM/ RTM at 120% of the energy charge. Further, under Rule 9(2)(i), gains from such sales accruing to the generator are capped at three paise per unit.

LPS Rule 9 formulation is a simple and effective mechanism to ensure gate closure for contracted capacity on a day-ahead basis and can facilitate trades in URS capacity. However, there appear to be several challenges to its implementation. To address these, the following changes in the rules and procedures are suggested:

a. Aligning scheduling timelines and practices at the state level to enable centralised participation. For example,
   - Some states do not have requisition-based scheduling as is the case with ISTS capacity
   - Ideally DISCOM should intimate schedules by 8:00 am as per the rules but timelines for uploading scheduling as per state grid codes are later than this makes generator participation challenging.
b. Easing 120% of energy charges cap for generator bids to 200% of regulated energy charge to account for month-on-month variations in fuel costs and dispute related pending dispensations which might affect the generator's final operational cost.
c. Removal of the three paise cap on generator earnings to incentivise generators to take efforts to ensure availability and participate in market, especially in peak periods. As the gains will be shared with DISCOMs, DISCOMs as capacity holders also benefit.

In addition, stringent/ enabling measures to ensure compliance, together with incentives, would be necessary:

a. Suo-motu proceedings by APTEL with respect to SERCs inaction in fixed charge disallowance due to non-compliance with LPS Rule 9.
b. Changes in standard bidding documents and model PPAs to enable sale of URS power as per Rule 9 by generator.
c. To address DISCOM concerns of losing "right to recall", Ministry of Power can provide incentives under central sector schemes for implementing day-ahead gate closure and providing standing instructions to contracted generators to comply with Rule 9.

We believe that operationalising gate closure and restricting the DISCOMs' right to recall on a day-ahead basis is a precondition for any of the capacity market proposals in the paper. The real test of whether the capacity market approach can succeed will come from the experience of operationalising Rule 9 in practice. A better assessment of the legal, procedural, and institutional changes that a structural redesign of this scale requires is also necessary; at present there is no clear view of the risks, gaming possibilities, and likely winners and losers under the proposed arrangement. Without this groundwork, undertaking a fundamental redesign of contracting mechanisms that have evolved over the past two decades risks serious harm to the sector. The implementation of capacity markets for reserves through annual contracts, and a standardised, centralised short-term market design, would also serve as good first steps to understand implementation issues in the Indian context and should be prioritised.

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