Submission of Comments on the

CERC Staff Paper on Capacity Market for Electricity in India

The Central Electricity Regulatory Commission (CERC) has issued a Staff Paper on Capacity Market for Electricity in India (April 2026) for stakeholder consultation. The staff paper proposes three market mechanisms, a) an RA Obligation Capacity Market, b) a Reserve Capacity Market, and c) a Secondary Short-Term Capacity Market intended to complement the existing energy-only market framework and address emerging adequacy, reliability, and efficiency challenges in the Indian power sector.

Accenture Solutions Private Limited submits the following comments and recommendations on the CERC Staff Paper to support the design of an effective, investable, and operationally feasible capacity market framework.

1. Sequencing and transition strategy for capacity market implementation

Context

The Staff Paper proposes three capacity market instruments simultaneously: the RA Obligation Capacity Market (Options 1, 2, and 3), the Reserve Capacity Market, and the Secondary Short-Term Capacity Market. While each instrument addresses a distinct market gap, the paper does not articulate a transition pathway or sequencing logic. India's power sector is at an early stage of resource adequacy compliance, with many states yet to finalise RA plans and distribution utilities accustomed to full fixed-cost recovery under take-or-pay PPAs. Introducing capacity markets that partially decouple fixed-cost recovery from availability guarantees represents a significant departure from current practice. The simultaneous rollout of multiple instruments risks creating regulatory complexity without the institutional readiness to manage it effectively.

Recommendation

CERC may consider prescribing a phased implementation roadmap for the three proposed instruments, anchored on specific preconditions and milestones rather than a fixed timeline. In particular:

- Phase 1 (Transition): Implement the Reserve Capacity Market and the Secondary Short-Term Capacity Market as foundational instruments. The Reserve Capacity Market addresses the immediate reserve shortfall through advance centralized procurement by NLDC, while the Secondary Short-Term Capacity Market unlocks stranded contracted capacity through a quarterly trading platform. Together they build institutional capacity, market liquidity, and operator familiarity before the more disruptive RA Obligation Market is introduced.

- Phase 2 (Pricing Reform): Introduce Net-CONE based capacity auctions for new capacity procurement while retaining full scheduling rights for discoms. This is the first genuine departure from current practice where the capacity remuneration shifts from guaranteed cost-plus recovery to market-discovered pricing, but discoms retain operational control over dispatch. Generators and investors absorb the transition to auction-based remuneration without the simultaneous shock of losing dispatch certainty for discoms.
- Phase 3 (Full Market): Remove scheduling rights entirely and move to capacity-charge-only auctions (Option 1 or Option 3), with dispatch fully indexed to DAM/RTM. This phase should be triggered only once measurable preconditions are met, including: defined minimum RA compliance rates across states, verifiable depth of the Day-Ahead and Real-Time markets expressed as a minimum share of total generation traded through exchanges, operationalization and regulatory approval of the Net-CONE estimation methodology by NLDC, and demonstrated energy market price stability that gives investors reasonable confidence in energy revenue supplementing the capacity charge.

Rationale

The risk of premature market design transition is well documented internationally. The success of capacity markets in PJM, Great Britain, and other jurisdictions was contingent on a functioning energy market, resource adequacy mandates backed by compliance enforcement, and institutional capability for forward planning and auction administration. India is still in the process of establishing these foundations. A phased approach would reduce regulatory risk, allow trust to be built in the market design, and enable course correction before full transition.

2. Net-CONE methodology: need for transparent, independently validated estimation

Context

Net-CONE (Net Cost of New Entry) is the foundational parameter for the demand curve in all three proposed capacity market instruments. The Staff Paper specifies that NLDC shall determine Net-CONE through market analysis and study, with the demand curve set at Net-CONE plus 10% as the bid cap. However, the paper does not specify the methodology for computing Net-CONE, the reference technology or plant to be used, the treatment of revenue from ancillary services and energy markets in deriving the net figure, the frequency of revision, or the mechanism for public consultation and regulatory approval of the estimated value. Given that Net-CONE will directly determine the price ceiling for capacity auctions and therefore the cost borne by distribution utilities and ultimately consumers, its methodological basis must be robust and transparent.

Recommendation

CERC may require NLDC to develop and publish a detailed Net-CONE estimation methodology for regulatory approval before operationalizing any capacity market auction. The methodology may cover:

- Identification of the reference plant (reference peaker or firm dispatchable capacity) that serves as the cost benchmark for new entry in the Indian context.
- Computation of gross CONE comprising capital costs, fixed operations and maintenance costs, and financing charges over the contract life, using transparent assumptions.
- Methodology for estimating expected energy market revenues and ancillary service revenues, and netting these from gross CONE to arrive at Net-CONE.
- Frequency of revision of the Net-CONE estimate (recommended: at minimum annually, aligned with each auction cycle) and a process for consultation before revision.
- Mechanism for stakeholder review, regulatory approval, and publication of the Net-CONE estimate prior to each auction, with sufficient lead time for market participants to prepare bids.

Rationale

Net-CONE is the most consequential parameter in capacity market design: it sets the price ceiling, anchors investor expectations, and determines consumer cost exposure. If Net-CONE is overestimated, capacity payments to generators exceed what is necessary, inflating costs for discoms and ultimately consumers. If underestimated, the capacity market fails to attract adequate investment, defeating its primary purpose. The risk of either outcome is significant if the estimation methodology is not grounded in rigorous, transparent, and independently validated analysis. International best practice including the GB capacity market, where the System Operator publishes Net-CONE calculations for public scrutiny before each auction, and PJM, where the Cost of New Entry is determined through an independent study updated periodically, provides a useful template for India to follow.

3. Adequacy of partial fixed-cost recovery for investment bankability

Context

All three RA Obligation Capacity Market options in the Staff Paper propose that generators receive only the capacity charge discovered through auction, with balance cost recovery expected from the energy market (DAM/RTM prices). This departs fundamentally from India's current practice of guaranteed full fixed-cost recovery linked to declared availability under long-term PPAs. The Staff Paper itself acknowledges the concern that partial capacity charge recovery

may not be sufficient to assure investors and financial institutions of investment recovery, and that a robust energy market and no-load-shedding requirement are necessary conditions. However, neither condition is fully met in India at present: energy market depth remains limited (approximately 7% of total generation traded through exchanges), and load shedding continues in several states.

Recommendation

CERC may consider the following safeguards to address bankability concerns without reverting to guaranteed full fixed-cost recovery:

- A floor capacity payment may be established equivalent to the minimum fixed cost component required to service project debt, with the balance recovered through the energy market. This floor would provide lenders with the payment certainty required for project financing while preserving market efficiency incentives.
- CERC may issue guidance on the treatment of capacity market revenues in project finance structures, working in coordination with RBI, financial institutions, and developers, to align lending norms with the partial-recovery model.
- The transition to full partial-recovery model (Option 1 or 3) may be preceded by a pilot phase under Option 2, which preserves scheduling rights and thus provides greater revenue certainty to generators during the transition.
- CERC may monitor energy market prices and depth metrics on a quarterly basis and publish a capacity market performance report, with a view to ensuring that energy market revenues are in fact supplementing capacity market receipts as the framework assumes.

Rationale

The viability of capacity markets in the US, UK, and Europe rests on three complementary conditions: a) deep and liquid energy markets with scarcity pricing that drives revenue during high-demand hours; b) no-load-shedding mandates that create a credible commitment to market dispatch; and c) institutional certainty around capacity auction design and payment. In India, these conditions are at an early stage of development. The transition away from take-or-pay PPAs requires careful design to avoid stranded investment or financing difficulties for new capacity, particularly for flexible and storage resources.

4. Capacity credit methodology for variable renewable energy and storage

Context

The Staff Paper recommends a technology-agnostic capacity market in which RE projects firmed up with Energy Storage Systems (ESS) may offer capacity on par with thermal resources. While this is a desirable long-term goal, the paper does not specify the de-rating factors or capacity credit methodology that would be applied to variable RE and RE+ESS resources bidding into the capacity market. The absence of a defined capacity credit framework creates ambiguity in how much capacity a solar, wind, or RE+ESS resource can offer in an auction, and may lead to either over-crediting (resulting in inadequate actual capacity during stress periods) or under-crediting (discouraging RE+ESS participation in capacity markets). CEA has separately issued a discussion paper on capacity credit methodology, and the capacity market framework should be aligned with it.

Recommendation

CERC, in coordination with CEA, may ensure that a clear capacity credit framework for all resource types is finalised and published before capacity market auctions are conducted. Specifically:

- Thermal, hydro, wind, solar, RE+ESS, and standalone storage resources should each have defined Effective Load Carrying Capability (ELCC) or equivalent de-rating factors, determined through probabilistic analysis rather than deterministic averaging.
- The capacity credit for solar should be evaluated against peak system stress periods (typically late afternoon/evening when solar output declines), and for wind resources against seasonal stress patterns, rather than average annual output.
- Seasonal and monthly load duration curve, and the use of stochastic methods to capture variability, should be considered in the final capacity credit methodology.
- Capacity credits should be reviewed and updated periodically (at minimum every three years, or upon significant changes in the generation mix) to reflect the changing marginal reliability contribution of resources as RE penetration increases.
- For RE+ESS resources, the capacity credit framework should clearly define the storage duration, depth of discharge, and round-trip efficiency assumptions underlying the credited capacity to ensure deliverability during stress events.

Rationale

Capacity credit methodology directly determines how much capacity a variable resource can offer in an auction and therefore whether the market procures sufficient firm capacity to meet

reliability standards. Methodologies based on median or average generation may not accurately capture the reliability contribution of variable resources, particularly as grid conditions change with rising RE penetration. A solar plant's average output across the year tells you very little about whether it will be available during a late evening stress event in October. The capacity credit must reflect the resource's contribution specifically during the hours when the system is most at risk not its average performance. System operators such as NYISO and PJM have moved toward hourly ELCC approaches precisely because simpler methods led to over-crediting of wind and solar, resulting in adequacy shortfalls during stress events. A rigorous, probabilistic, and stress-period-anchored capacity credit framework is therefore a prerequisite for a well-functioning technology-agnostic capacity market, without it, the market may clear with apparently adequate capacity on paper while the system remains vulnerable during actual stress conditions.

5. Scheduling rights transition: managing discom acceptance and financial impact

Context

Options 1 and 3 of the RA Obligation Capacity Market propose that distribution utilities (discoms) relinquish scheduling rights over contracted capacity, with dispatch indexed entirely to the Day-Ahead and Real-Time markets. This is a fundamental change in the operating model of discoms, which currently exercise scheduling rights over PPAs as the primary mechanism for ensuring supply security and managing demand variability. Discoms bear significant long-term power purchase commitments and have built their procurement and financial planning models around guaranteed scheduling rights. Loss of these rights introduces new supply security risks and uncertainty around demand coverage, particularly for discoms in states with limited financial flexibility or inadequate RA compliance frameworks.

Recommendation

CERC may provide a structured transition pathway for the relinquishment of scheduling rights, with appropriate risk mitigation mechanisms. Specifically:

- Option 2 (scheduling rights retained until the Day-Ahead market window) should be implemented first, allowing discoms to adapt their planning and procurement models to the market-dispatch paradigm before moving to full removal of scheduling rights.
- CERC may require discoms to develop transition plans that detail how they will manage supply security and demand coverage during the transition from scheduling-right-based contracts to market-dispatch-based arrangements.
- The demand-curve design for discoms, specifically the provision that discoms bid slightly above the price cap to guarantee capacity coverage requires careful calibration to

prevent inflationary effects on the Market Clearing Price. CERC should model the MCP impact of this provision under different scenarios before finalising the design.

- State Electricity Regulatory Commissions (SERCs) may be advised to ensure that the financial implications of scheduling rights removal are incorporated into tariff determinations and power procurement planning approvals, so that discoms are not exposed to unforeseen revenue shortfalls.

Rationale

Accenture's comments on the Draft National Electricity Policy, 2026 highlighted the importance of phased and predictable transition mechanisms when introducing structural changes that affect the financial stability of distribution utilities. Sudden loss of scheduling rights without adequate transition support could lead to supply security risks, revenue uncertainty, and resistance from state utilities that may undermine implementation of the capacity market framework. A staged approach, aligned with progressive RA compliance and energy market depth improvements, would reduce transition risk.

6. Reserve Capacity Market: triggers, exit criteria, and cost allocation transparency

Context

The Reserve Capacity Market is proposed as a transitional instrument to address the acute shortfall of secondary and tertiary reserves, particularly during solar hours when thermal units operate at minimum turn-down levels. The Staff Paper proposes annual advance procurement of reserves by NLDC, with costs allocated to reserve-deficient states. While the design intent is sound, the paper does not specify the criteria that would trigger the exit from advance procurement once RA compliance is achieved, the mechanism for setting and reviewing reserve allocation by NLDC across states, or the transparency and dispute resolution framework for cost allocation to deficient states. The risk of indefinite continuation of a transitional mechanism without defined exit criteria is a governance concern.

Recommendation

CERC may strengthen the Reserve Capacity Market design with the following provisions:

- Define measurable exit criteria for the advance reserve procurement mechanism, such as: all states achieving RA compliance above a defined threshold for two consecutive years; and system reserve adequacy metrics (secondary and tertiary reserve availability) meeting IEGC requirements consistently during peak and solar hours.
- NLDC's reserve allocation methodology and the basis for determining state-wise shortfall should be published transparently and be subject to a formal consultation process, with

states having an opportunity to contest allocations before procurement is initiated on their behalf.

- The commitment/holding charge for Scenario 2 (capacity scheduled but not dispatched) should be defined clearly in advance and be based on a transparent opportunity cost calculation, to avoid disputes and ensure cost predictability for deficient states.
- An annual review mechanism should be established to assess whether the Reserve Capacity Market is achieving its intended objectives, with findings reported to CERC and published for stakeholder review.
- The aggregator model for RE+ESS participation in the Reserve Capacity Market as described in the Staff Paper requires a regulatory framework for aggregator licensing and settlement. CERC may align this with the aggregator framework proposed under the Draft National Electricity Policy, 2026.

Rationale

Germany's experience with Strategic Reserves illustrates both the value and the governance challenges of advance reserve procurement mechanisms. The key lesson is that cost allocation transparency, well-defined triggers for activation and exit, and prohibition on market participation by contracted reserves are essential for the mechanism to function without distorting the energy market. The Draft National Electricity Policy, 2026 also emphasises the need for market mechanisms to complement long-term planning and for system operators to maintain transparent procedures for scheduling and dispatch. The Reserve Capacity Market design should reflect these principles.

7. Secondary Short-Term Capacity Market: market depth and gaming prevention

Context

The Secondary Short-Term Capacity Market is intended to unlock silo-based contracted capacity and enable trading of existing contracted capacity on a quarterly or monthly basis. This is a pragmatic near-term measure given that India's power exchanges currently trade approximately 7% of total generation, and significant contracted capacity is invisible to the market due to bilateral scheduling arrangements. However, the effectiveness of the short-term capacity market will depend critically on the depth of participation, both on the supply side (discoms and generators with surplus capacity) and the demand side (discoms with deficits). The paper does not address how the market will be populated initially, or how gaming risks including strategic withholding of capacity to influence MCP will be managed.

Recommendation

CERC may consider the following measures to ensure effective operationalisation of the Secondary Short-Term Capacity Market:

- A market monitoring and surveillance framework should be established for the secondary capacity market, with clear rules on market manipulation, strategic withholding, and concentration of capacity among a limited number of sellers. The Market Monitoring Unit at CERC may be empowered to review capacity market outcomes alongside energy market monitoring.
- CERC may consider a mandatory participation obligation for generators with surplus capacity above a defined threshold to offer such capacity into the short-term capacity market, at least during initial years, to ensure market depth.
- The design of the short-term capacity market should be aligned with the co-optimisation of energy and ancillary services to prevent sub-optimal dispatch outcomes arising from siloed capacity and energy market interactions.
- The contract-for-difference (CfD) mechanism being piloted for merchant RE+BESS projects may be examined for its compatibility with, and potential to enhance liquidity in, the short-term capacity market.

Rationale

The effectiveness of short-term capacity markets depends on competitive market depth. In California, backstop procurement mechanisms for resource adequacy have at times resulted in exercise of market power by suppliers aware of the ISO's procurement obligation. India's energy-only markets have also experienced price spikes during high-demand periods that reflect thin supply-side participation. The secondary capacity market will need robust market monitoring from inception to prevent the same dynamics from transferring into capacity price formation.

8. Penalty mechanism: calibration and due process framework

Context

All three market instruments in the Staff Paper prescribe a penalty of 1.5 times the discovered capacity charge for failure by capacity providers to bid as price takers and clear in the market during peak/stress hours notified by NLDC. While a strong penalty is necessary to prevent gaming and ensure capacity is genuinely available during system stress, the paper does not address the process for determining non-compliance, the conditions that would constitute force majeure or legitimate non-delivery (e.g., forced outage, fuel supply failure), or the mechanism

for disputed penalty determinations. Overly rigid penalty application without due process provisions could deter capacity market participation, particularly from new entrants and smaller providers.

Recommendation

CERC may supplement the penalty provisions with a clearly defined compliance and due process framework, including:

- A transparent notification mechanism through which NLDC communicates peak/stress hour periods to capacity providers with adequate advance notice, and a clear definition of the conditions under which the price-taker obligation is activated.
- Defined grounds for force majeure and partial non-performance that would reduce or waive penalty exposure, including forced outages, transmission constraints preventing delivery, and fuel supply disruptions documented with supporting evidence.
- A dispute resolution mechanism under which capacity providers may challenge penalty determinations before a designated authority within CERC, with defined timelines for resolution.
- Graduated penalty provisions: for a first occurrence of non-compliance, a warning and remediation plan; for repeated or systemic non-compliance, escalating penalties up to and including capacity contract termination.

Rationale

The effectiveness of capacity market penalties depends on their credibility, not just their magnitude. Penalties set at punitive levels without adequate due process risk legal challenges and may chill participation. The GB Capacity Market provides for capacity providers to submit reason for non-performance, with penalties applied only after review. PJM similarly allows generators to present evidence of unexpected outages before performance charges are finalised. India's capacity market framework should incorporate similar procedural safeguards.

9. Demand response and demand-side resources in capacity markets

Context

The Staff Paper references Load Serving Entities (LSEs) and large consumers primarily as buyers of capacity, following international models. However, it does not explicitly address the potential for demand response resources, flexible large consumers, and aggregated distributed resources to participate as capacity providers in the proposed market mechanisms. The Draft National Electricity Policy, 2026 recognises demand-side flexibility as a resource for system planning and reliability, and international capacity markets including PJM and the GB Capacity Market

explicitly include demand-side response as eligible capacity. As India's demand composition evolves with electrification of transport, industrial flexibility, and distributed generation, demand-side resources will become increasingly important to cost-effective capacity adequacy.

Recommendation

CERC may explicitly recognise demand response and aggregated demand-side resources as eligible capacity providers in all three proposed market instruments. The enabling framework may include:

- Defined measurement and verification protocols for demand response capacity, including baseline determination methodology and performance measurement during stress event activations.
- Eligibility criteria for demand response resources bidding into the Reserve Capacity Market, including minimum dispatchable demand quantum, response time requirements, and duration obligations.
- A framework for aggregators to pool demand-side resources for capacity market participation, aligned with the aggregator regulatory framework being developed under the Draft National Electricity Policy, 2026.
- A review of demand response participation rules after two years of capacity market operation, with a view to expanding eligible demand-side resource types as experience accumulates.

Rationale

Demand-side participation in capacity markets reduces overall system cost by providing a non-generation alternative for meeting peak reliability requirements. In PJM, demand response has consistently provided 15–20% of cleared capacity in base residual auctions, moderating capacity prices. India's large industrial and commercial load base, combined with growing adoption of behind-the-meter generation and storage, offers significant demand-side flexibility potential. Explicitly including demand-side resources in capacity market design from the outset would set the right signals for investment in demand-side flexibility.

10. Institutional readiness and governance framework for capacity market administration

Context

The CERC Staff Paper envisages NLDC as a key institutional actor in the Reserve Capacity Market, responsible for reserve allocation, advance procurement, dispatch, and cost allocation to deficient states. For the RA Obligation Capacity Market (Option 3), a central agency designated by the Ministry of Power is proposed to administer centralised auctions for residual RA capacity.

The paper does not elaborate on the institutional capacity, legal mandate, systems infrastructure, and governance framework required for these entities to effectively administer complex multi-year capacity auctions, manage performance monitoring, administer penalties, and handle dispute resolution. Given the scale and complexity of the proposed framework, institutional readiness is a first-order challenge.

Recommendation

CERC may initiate a parallel workstream on institutional readiness alongside the consultative process on capacity market design. This may include:

- A capacity assessment of NLDC and the proposed central agency against the functional requirements of capacity market administration, covering auction management, Net-CONE estimation, performance monitoring, penalty administration, and dispute resolution.
- Development of the IT systems and data infrastructure required for capacity market registry, participant registration, bid submission, auction clearing, capacity payments, and performance tracking.
- Engagement with power exchanges to assess their potential role in secondary short-term capacity market administration, building on their existing trading platform infrastructure and experience with energy market auctions.
- A regulatory framework for the central agency administering the Residual RA Obligation Capacity Market (Option 3), including its legal constitution, oversight by CERC, audit and reporting obligations, and dispute resolution jurisdiction.
- Capacity-building programmes for state regulators, SLDCs, and distribution utilities on the capacity market framework, given that effective RA compliance by states is a prerequisite for the framework to function as designed.

Rationale

Institutional readiness is consistently cited in international capacity market reviews as a critical determinant of implementation success. The GB Capacity Market took several years from policy announcement to first auction, with significant investment in IT systems, pre-qualification frameworks, and regulatory guidance. India's implementation timelines will need to be matched by accelerated institutional preparation. Without robust implementation infrastructure, well-designed capacity market frameworks can underperform or create unintended market distortions.

Conclusion

Accenture Solutions Private Limited welcomes the CERC Staff Paper as an important step toward establishing a structured capacity market framework for India. The proposals reflect a thoughtful adaptation of international models to the Indian context and address genuine market failures in resource adequacy, reserve procurement, and short-term capacity flexibility.

The comments submitted above are intended to strengthen the framework by addressing transition sequencing, methodological robustness, investment bankability, technology-neutral capacity crediting, discom transition management, governance transparency, demand-side inclusion, and institutional readiness. We believe that a well-sequenced, methodologically sound capacity market framework developed through continued stakeholder engagement can deliver material improvements in India's power system reliability and market efficiency.

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