दामोदर घाटी निगम
DAMODAR VALLEY CORPORATION

No. Coml./Tariff/CERC/20/ 1821

Date: 15.06.2026

To
The Secretary
Central Electricity Regulatory Commission,
7th Floor, Tower B, World Trade Centre,
Nauroji Nagar,
New Delhi -110029

Sub.: Comments/Suggestions on Staff Paper on Capacity Market for Electricity in India.

Ref: - Public Notice vide no. RA-14027(12)/1/2026-CERC Dated: 29.04.2026

Respected Sir,

With reference to the Public Notice mentioned above, please find enclosed Comments/Suggestions on Staff Paper on Capacity Market for Electricity in India. DVC humbly prays before this Hon'ble Commission to kindly consider the comments/suggestions.

Thanking You.

Yours faithfully,

Sr. General Manger (Commercial)

Encl: - As stated

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Note on Capacity Market for Electricity in India

Comments / Suggestions of Damodar Valley Corporation (DVC) on the CERC Staff Paper on "Capacity Market for Electricity in India"

PREAMBLE

Damodar Valley Corporation (DVC), a multi-purpose statutory body under the Ministry of Power (Govt. of India), operating an integrated generation, transmission and distribution system across West Bengal and Jharkhand, welcomes the opportunity to comment on the Staff Paper. DVC supports the broad intent of CERC's staff to (a) operationalize Resource Adequacy (RA), (b) cure the "missing-money" problem, (c) ensure availability of capacity during system-stress hours, and (d) deepen India's short-term markets. The following comments are submitted for kind consideration.

A. General Comments

1. **Sequencing with the RA Framework is critical.** The MoP RA Rules, 2022 and the CEA RA Guidelines are still in the implementation phase across States. Introduction of a fully market-based capacity construct (Net-CONE based, market-indexed dispatch) before mandatory RA is uniformly enforced may expose vertically integrated entities like DVC—who serve "all-load-meet" obligations to two State Governments and direct industrial consumers—to dual regulatory burden. **Suggestion:** A glide-path/transition of at least 3–5 years be provided, during which existing Section-62/Section-63 PPAs are insulated and the new design applies only prospectively to fresh capacity tie-ups.
2. **Treatment of Legacy/ Existing PPAs.** The Staff Paper is largely silent on the treatment of long-term PPAs already in force. Migrating these to a Net-CONE based capacity construct would require contractual re-opening, regulatory

approval, and may impact lender comfort. **Suggestion:** The Commission may explicitly clarify that all subsisting PPAs concluded under Section 62/63 shall continue on existing terms till their natural expiry, and the proposed capacity market mechanism shall apply only to (i) re-tied capacities post expiry and (ii) new capacity additions

3. **Special status of multi-purpose / composite utilities.** DVC, being a composite utility (Gen + Transco + Discom under a single statute, Section 14 proviso of the Electricity Act, 2003), self-balances a substantial part of its load through its own generation. Capacity obligation framework should recognize **self-supply / captive arrangements** of such composite entities and not compel them to participate in centralized auctions for the self-served portion. **Suggestion:** Clear carve-out for self-scheduled, self-balanced capacity of composite utilities and CPPs.

B. Comments on Capacity Market for RA / Capacity Obligation (Para 26–27)

Option 1 (Capacity-charge-only bid; 15-yr contract; market-indexed dispatch)

4. **Risk allocation for the generator is skewed.** Recovering the variable/energy component purely through MCP transfers fuel-price and FGD/coal-linkage risks entirely to the generator, whereas in India fuel supply (FSA, GCV, washery rejects, rail logistics) is exogenous and largely a pass-through under existing tariff regulations. Linking energy-charge recovery to MCP—which itself is capped at Rs 10/kWh—could lead to under-recovery during high-coal-price cycles (as witnessed in 2022). **Suggestion:** Either (i) retain a regulated fuel-cost pass-through within the capacity-only design, or

(ii) provide an indexation formula (linked to coal price/GCV) over and above MCP for the contracted capacity

5. **Demand curve "above price-cap" mechanism (Para 27, bullet 5) is problematic.** The Staff Paper itself flags that this could *inflate the MCP* and is being recommended only to address free-rider issues. Drawing a discom's bid above the price-cap effectively guarantees clearance and may distort price signals for the entire market, harming open-access consumers and traders. **Suggestion:** Instead of bidding above the price-cap, adopt a **must-run/must-clear obligation** on the capacity provider with a **financial-only settlement** (Contract-for-Difference / two-way CfD) between the discom and the generator, so that physical market discovery remains undistorted while the discom is hedged
6. **15-year contract length** is welcome for bankability. However, lenders typically seek 20–25 years for greenfield thermal (matching debt tenor). **Suggestion:** Permit contract duration of **up to 20–25 years for greenfield thermal/hydro/PSP** and 10–15 years for re-tying of existing capacity, mirroring international practice (PJM allows up to 20 yrs for new entrants)
7. **Penalty of 1.5x capacity charge for non-clearance during stress hours** is reasonable, but the **definition of "peak/stress hours" by NLDC** must be transparent, ex-ante notified (e.g., day-ahead), and based on objective triggers (e.g., margin <5%, frequency excursion). Real-time/ex-post designation will create un-hedgeable risk. **Suggestion:** Codify stress-hour determination in the Detailed Procedure and cap the number of stress-hour blocks per annum.

Option 2 (Total-cost bid; scheduling but no dispatch right)

8. Option 2 is closer to the existing Section-63 design and easier to operationalize. However, the **denial of dispatch rights** while retaining scheduling rights creates an ambiguous position. If the generator is dispatched against the discom's schedule through the market and clears at MCP lower than variable cost, who absorbs the loss? **Suggestion:** Clarify that the discom's bilateral settlement with the generator (CfD) shall make the generator whole for the *total contracted cost*, irrespective of MCP outcome, against guaranteed delivery during scheduled hours.

Option 3 (Centralized "Residual RA" auction)

9. Option 3 in principle acts as a **back-stop** mechanism. However, the **identity of the "Central Agency"** should be clearly specified—preferably **NLDC/Grid-India**, with PFC/REC or PXIL/IEX as the auction platform, and **CTUIL** as the settlement nodal agency to leverage existing payment-security architecture. Additionally, cost allocation purely to the deficient discom may be insufficient if the underlying cause is regulatory delay at SERC level. A **performance-linked penalty** on deficient discoms (over and above the auction price) should be considered to drive discipline.

C. Comments on Reserve Capacity Market (Para 28–37)

10. The proposal for advance procurement of Secondary and Tertiary Reserve capacity, given the acute shortage during solar hours and the recurring use of Section-11 directions, will provide much-needed visibility and revenue stream for flexible, ramp-capable plants

11. **Eligibility should explicitly include:**

- Existing thermal stations capable of two-shift / low-load operation which can offer 5–10% of installed capacity as TRAS.

- **Pumped Storage Plants (PSP)** including under-construction/upcoming PSPs.
- **BESS co-located with thermal/hydro** (hybrid resources) on a de-rated capacity basis
- Demand Response aggregators (industrial consumers).

12. **Annual auction with one-year contract (Para 37)** is too short to incentivize *new* capacity (BESS/PSP). **Suggestion:** Provide a **dual-track auction**:
    - Short-track: 1-year contract for existing flexible capacity (annual auction)
    - Long-track: 7–10 years for new BESS/PSP/RE+Storage, with the demand curve appropriately escalated for bankability
13. **Cost allocation to "reserve-deficient States"** (Para 37, last bullet) should be carefully calibrated. Where a State has long-term tied-up capacity but the *generator* has not declared availability for reserves (e.g., under outage), the cost should fall on the generator, not the State. **Suggestion:** Introduce a counter-party identification matrix for cost allocation distinguishing between (a) State/discom shortfall, (b) generator unavailability, (c) genuine system events
14. **Scenario 3 (Para 37): capacity not requisitioned by NLDC—provider receives capacity charge + MCP from energy market.** This may lead to a windfall during high-MCP hours since the provider has already been paid an availability premium. **Suggestion:** Cap the MCP-side recovery at "Variable Cost + reasonable margin" or apply a clawback above a threshold MCP, similar to PJM's Energy & Ancillary Services Offset

D. Comments on Secondary / Short-Term Capacity Market (Para 38–39)

15. Creation of a short-term capacity market will allow surplus-capacity utilities to monetize spare capacity and enable deficit utilities to firm up their portfolio without entering long-term obligations.

16. **Auction frequency of "every three months for three months" (Para 39):** Three-monthly granularity is acceptable, but **monthly and weekly contracts** should also be permitted to align with the seasonality of Indian demand (e.g., paddy/agricultural pumping in Jharkhand–Bengal during Kharif). **Suggestion:** Provide a tiered product portfolio—Quarterly, Monthly, Weekly capacity contracts.

17. **Treatment of capacity already tied under long-term PPA but temporarily surplus** must be clarified. GenCos have back-down/URS scenarios where the originally contracted discom does not requisition; the generator then sells surplus URS in DAM/RTM. The **Short-term Capacity Market should explicitly permit such surrendered/URS capacity to be re-traded as capacity (not just energy)**, with proceeds shared with the original beneficiary discom under the existing CERC sharing mechanism.

18. **Penalty of 1.5x total cost** (Option 2) is steep; consider tiered penalty—1.0x for first default, 1.5x for repeat, with cure-period provisions.

E. Other Specific / Drafting Suggestions

19. **Payment Security Mechanism (PSM):** The Staff Paper does not address PSM for capacity payments. Given the financial position of several discoms, **L/C + Tri-partite Agreement + LADF/PSM regulations** must explicitly cover capacity-charge dues, with rights of regulation under LPS Rules, 2022.

20. Treatment under Late Payment Surcharge (LPS) Rules, 2022 should expressly include "Capacity Charge" as a component of "outstanding dues."

21. **Alignment with Market-Based Economic Dispatch (MBED)/SCED**: The capacity market design should be harmonized with the upcoming MBED rollout to avoid double-optimization conflicts

22. **Emissions / Environmental Compliance:** Under Net-CONE based bidding, the cost of FGD, SCR, and other environmental compliance (MoEFCC Notification, Dec 2015 as amended) must be unambiguously included in the CONE computation; otherwise older thermal plants with mandatory retrofits will be at a disadvantage.

23. **Treatment of Hydro and PSP:** Hydro plants provide significant flexibility. Storage-type hydro and PSP should be eligible for both the RA Capacity Market and Reserve Capacity Market with appropriate de-rating factors notified by CEA.

24. **Inter-State vs Intra-State Capacity Markets:** Clarity is needed whether the proposed market is at the ISTS level only or extends to STU-connected capacity. DVC's portfolio straddles both ISTS and STU-connected loads. **Suggestion:** A unified national platform with regional clearing zones would maximize efficiency.

25. **Governance & Dispute Resolution:** A dedicated dispute resolution mechanism (Market Surveillance Committee under CERC) is recommended, given the multi-party, multi-settlement nature of the proposed markets.

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