

===== Forwarded message =====

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Date: Mon, 06 Apr 2026 17:01:18 +0530

Subject: IWPA Comments on the Proposed Revision of Congestion Charge Rates and the Question of Grid Planning Accountability as a Pre-Condition for Equitable Levy.

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Dear Sir,

We refer to the Order dated 13th March 2026 in Petition No. 1/SM/2026 in the matter of "*Rate of Congestion Charge in Real-Time Operation in Inter-State Transmission of Electricity*", wherein comments from stakeholders have been invited.

In this regard, the Indian Wind Power Association (IWPA) is pleased to submit its comments on the *Proposed Revision of Congestion Charge Rates and the Question of **Grid Planning Accountability as a Pre-Condition for Equitable Levy***. The same is attached herewith for your kind perusal.

We kindly request the Hon'ble Commission to consider the submissions favorably.

Best Regards,
M.Mohankumar,
Secretary General



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IWPA Comments On the Proposed Revision of Congestion Charge Rates_060426.pdf
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PART I: PRELIMINARY STATEMENT

1.1 These comments are filed in response to CERC Order dated 13.03.2026 in Petition No. 1/SM/2026, whereby the Commission has proposed to revise the rate of congestion charge from the existing flat Rs. 5.45/kWh to a dynamic rate of 1.5 times the applicable DSM rate (Reference Rate, Contract Rate, or Normal Rate), subject to a floor of Rs. 3/unit and a ceiling of Rs. 10/unit.

1.2 While the commenter supports the principle of periodically revisiting the congestion charge mechanism to align it with current regulatory frameworks — specifically the transition from UI to DSM — this submission raises a fundamental question that the Commission's Order does not address: *where a congestion event is demonstrably caused by inadequacy or delay in transmission infrastructure planning and execution by the Central Transmission Utility (CTU) or State Transmission Utilities (STUs), is it legally and technically justifiable to impose a congestion charge on generators whose deviations are an involuntary consequence of that infrastructure failure?*

1.3 The Commission is respectfully urged to: (a) address the question of grid planning accountability as part of this revision; (b) introduce a mechanism to distinguish behavioural congestion from structural congestion attributable to transmission planning failure; and (c) direct NLDC to publish corridor-specific congestion attribution analysis as a prerequisite to finalising any revised charge structure.

PART II: THE FUNDAMENTAL ASYMMETRY IN THE CURRENT FRAMEWORK

2.1 Original Design Premise vs. Present Ground Reality

The congestion charge framework under CERC (Measures to Relieve Congestion in Real Time Operation) Regulations, 2009, was premised on a behavioural model: entities *choose* to overdraw or under-inject, and a sufficiently high price signal will deter that behaviour. The original rate of Rs. 5.45/kWh was specifically calibrated against the marginal cost of liquid fuel generation — the counterfactual available to overdrawing states in 2010.

The framework assumes all entities can respond to price signals. Renewable energy is non-dispatchable, variable, and uncontrollable. RE generators lack mitigation tools unlike DISCOMs or conventional generators. Liability without control renders the framework arbitrary

This premise was valid when: (i) generation was predominantly thermal and dispatchable; (ii) RE penetration was negligible; and (iii) the primary cause of congestion was commercial behaviour — states gaming the UI mechanism. **All three conditions have fundamentally changed.**

2.2 The Structural Congestion Problem: What the Data Shows

The Commission in Para 8 of its Order acknowledges that *"in the last 15 years, there have been significant changes in the power system, market mechanisms, and energy mix."* The Commission, however, does not take the next analytical step: that the dominant form of congestion in India's grid today is **structural** — caused by the mismatch between generation commissioning and transmission capacity — not behavioural.

The following publicly available, authoritative data establishes this conclusively:

Table 1: Evidence of Structural Transmission-Side Congestion (2024–2025)

Metric / Finding	Quantum / Detail	Source
RE capacity stranded nationally due to transmission bottlenecks	~50 GW (as of June 2025)	IEEFA, June 2025
RE capacity stranded in Rajasthan alone	~8 GW out of 22 GW ISTS-connected RE	IEEFA, July 2025
Solar/wind curtailment in Rajasthan (Mar–Aug 2025)	~4 GW at peak; up to 51.5% during 10:30 AM–2:30 PM	Mercom India, Oct 2025
ISTS solar energy curtailed nationally (May–Dec 2025)	2.3 TWh — enough to power ~400,000 homes for a year	Ember Energy, Jan 2026
T-GNA solar capacity facing complete curtailment (Dec 2025)	~4 GW on select days	Ember Energy, Jan 2026
Estimated financial losses to 30+ solar/wind plants (Mar–Aug 2025)	Up to Rs 700 crore (~\$80 mn)	Down To Earth / DTE, Oct 2025
Transmission system (765 kV Bhadla–Sikar, Khetri–Narela etc.) delays	18–20 months beyond scheduled commissioning	NSEFI letter to MNRE (cited: Mercom India, Oct 2025)
States experiencing 10–30% curtailment during peak solar hours	Gujarat, Maharashtra, Tamil Nadu (in addition to Rajasthan)	Mercom India, Oct 2025
Substation capacity addition in April–January 2024-25 vs. plan	51,500 MVA added — 33% short of planned target	Outlook Business / ICRA, Jan 2026
CEA Chairperson's public admission (Sep 2025)	"Renewable capacity is expanding faster than the system's ability to absorb it"	CEA Chairperson at FICCI India Energy Transition Summit, Sep 2025
New RE project awards slump (Apr–Nov 2025-26)	Only 5.8 GW awarded vs. 40.6 GW in 2024-25 — partly due to transmission uncertainty	ICRA, cited in Outlook Business, Jan 2026

The sheer scale — 50 GW stranded nationally, 2.3 TWh curtailed in a single year — demonstrates that the dominant driver of congestion is not generator behaviour but a

systemic failure to commission evacuation infrastructure in time with generation capacity addition.

2.3 The CAG Has Documented Transmission Planning Failure Conclusively

The Comptroller and Auditor General of India, in **Report No. 9 of 2020** (Performance Audit of Planning and Implementation of Transmission Projects by PGCIL during XII Plan 2012–2017), found the following:

- Out of 18 transmission projects selected for audit, only 2 were completed within the scheduled time.
- 13 projects were completed with delays ranging from 4 to 71 months.
- 3 projects were still under execution with anticipated delays of 6 to 109 months.
- PGCIL's long-term planning focused exclusively on 'transmission capacity' rather than 'Total Transfer Capability' (TTC) — the parameter that actually determines how much power can reliably flow. No TTC targets were declared for four consecutive years, in violation of CERC regulatory requirements.
- At the end of the XII Plan (March 31, 2017), TTC of different inter-regional corridors ranged between only 19.97% and 83.66% of their respective installed transmission capacity — a systemic underutilisation caused by planning inadequacy, not generator behaviour.
- No network plan was found available in CTU's records or website, in violation of Ministry of Power guidelines.

Critically, CAG observed: *"Inadequacies in transmission network and delay in commissioning of transmission projects may not only result in loss of revenue for PGCIL but may also lead to congestion in evacuation of power."* (CAG Report No. 9/2020, Chapter 1). The Commission is already in possession of this finding.

A further CAG performance audit in 2014 (Report for 2007–2012) identified the same pattern, establishing that transmission planning failures and consequent congestion are a **multi-decadal, recurring institutional problem** — not an episodic operational matter.

PART III: LEGAL AND REGULATORY GROUNDS FOR DISTINGUISHING STRUCTURAL CONGESTION

3.1 The Forced Outage Exemption Analogy

The Commission has, both in the 2009 Regulations and in the proposed revision at Para 12(b), retained the following exemption:

No congestion charge shall be levied for congestion in a transmission corridor if the power flow on the corridor is as per the schedule, but the congestion has been caused by forced outages of a line in the corridor, which occurs after the drawal schedule has been fixed.

This exemption embodies a sound principle of administrative law: **an entity should not be penalised for a grid-side event beyond its control.** A forced outage is a grid-side event. Chronic under-capacity of a corridor caused by delayed commissioning of transmission

infrastructure is *no different in principle* — in both cases, the generator's deviation is not the proximate cause of congestion; the transmission system's failure is.

The Commission is urged to extend this principle by analogy to **structurally congested corridors** — defined as corridors where Available Transfer Capability (ATC) has been demonstrably insufficient relative to the committed generation capacity for a period exceeding, say, six months — and exempt generators from congestion charges on such corridors for so long as the structural deficit persists.

3.2 Provisions of the Electricity Act, 2003

Section 33 of the Electricity Act places grid security obligations on NLDC/RLDCs. **Sections 38 and 39** place transmission planning obligations on the CTU and STUs respectively. These sections contemplate that the grid planners bear accountability for grid adequacy. Section 79(1)(h) empowers this Commission to regulate interstate transmission — which implicitly requires ensuring that commercial charges imposed in the name of grid security are directed at actual grid security failures, not at involuntary consequences of grid planning failure.

Imposing congestion charges on RE generators for curtailment caused by infrastructure delays for which CTU and STUs are institutionally responsible — with no corresponding accountability mechanism on the planning side — creates an asymmetry not contemplated by the Electricity Act.

3.3 Constitutional Proportionality

A congestion charge is a penalty in substance. Basic principles flowing from Article 14 of the Constitution, as applied in regulatory penalty contexts, require that penalties be proportionate and directed at the party actually at fault. Applying uniform penalties violates Article 14. The Supreme Court and APTEL have applied proportionality review in regulatory penalty cases. Where congestion is demonstrably structural, imposing full congestion charges on generators — whose only 'fault' is that the grid was not built to match their commissioned capacity — does not satisfy proportionality.

3.4 RTM Access Asymmetry

ASSOCHAM's submission (Para 7 of the Commission's Order) correctly identified that while DISCOMs may now use the Real Time Market (introduced 01.06.2020) to manage over-drawal, the Indian Electricity Grid Code **does not permit RE generators to purchase power from RTM when under-injecting**. Further, RE generators cannot revise TGNA contracts in real time. This asymmetry — DISCOMs have a market remedy, RE generators do not — makes the imposition of equal congestion charges on RE generators for under-injection technically unjustifiable. The Commission's Order (Para 10) does not engage with this asymmetry.

3.5 Double Penalty Problem

RE generators already face DSM charges for deviations under CERC (DSM and Related Matters) Regulations, 2024. The proposed structure at Para 12(a) of the Order imposes congestion charges of 1.5× the DSM rate *on top of* DSM charges for the *same deviation*. This creates a dual penalty for a single act, where the second penalty (congestion charge) is levied on a generator that may have been physically incapable of controlling its deviation due to: (a) weather variability, (b) IEGC must-run status prohibiting output reduction without grid security justification, or (c) the absence of evacuation capacity.

PART IV: SPECIFIC PRAYER AND PROPOSED DIRECTIONS

In view of the foregoing, the following specific prayers are respectfully submitted before the Commission:

Table 2: Specific Prayers and Justification

#	Prayer / Direction Sought	Regulatory / Legal Basis
1	Direct NLDC to publish, within 60 days, a corridor-wise congestion attribution analysis distinguishing (a) behavioural congestion caused by entity over-drawal/under-injection, and (b) structural congestion caused by ATC being below committed/contracted capacity levels — and to make this analysis publicly available before the final order on congestion charges.	Section 33 EA 2003; CERC Regulation 5, Congestion Charge Regulations; natural justice
2	Introduce a 'Structural Congestion Suspension Mechanism': where NLDC's own data shows that ATC on a corridor has been below committed capacity for more than 180 consecutive days due to delayed commissioning of associated transmission infrastructure, congestion charges shall be suspended for all generators in that corridor for the duration of the shortfall.	Forced outage exemption by analogy (existing Para 12(b)); proportionality; Sections 38-39 EA 2003
3	Require CTU/STU to face a mirroring accountability mechanism — a reduction in transmission fixed charge recovery (as a percentage of annual fixed charges) — for each month that a corridor's ATC remains below committed levels due to delayed project commissioning beyond CERC-approved timelines. This creates symmetric incentives.	Section 79(1)(h) EA 2003; CERC Tariff Regulations; CAG Report No. 9/2020 findings
4	Provide explicitly in the revised regulation that no congestion charge shall be levied on RE generators for under-injection deviations in any time block where: (a) the deviation is within the weather-driven forecast error band; AND (b) the generator is operating under a T-GNA framework on a congested corridor. The DSM regime already covers such deviations; a second charge is disproportionate.	DSM Regulations 2024; IEGC must-run status; proportionality; RTM access asymmetry
5	Direct that the revised congestion charge framework not come into force for RE generators operating under T-GNA on congested corridors until the Structural Congestion Suspension Mechanism in Prayer 2 above is fully operationalised.	Natural justice; sequencing of regulatory interventions; investment viability of 500 GW RE target

PART V: WIDER POLICY CONTEXT AND INVESTMENT/FINANCIAL RISK

India's Ministry of New and Renewable Energy has set a target of 500 GW non-fossil capacity by 2030. Achieving this target requires approximately Rs. 4 crore per MW in new investment — implying over Rs. 2 lakh crore per 50 GW. The government's own financial institutions have deployed Rs. 10.79 lakh crore into renewable projects since 2014.

New RE project awards collapsed to 5.8 GW in April–November 2025-26, down from 40.6 GW in 2024-25, partly driven by transmission uncertainty. ICRA has explicitly flagged that transmission connectivity concerns are deterring new bids.

Imposing escalated congestion charges — up to Rs. 10/unit under the proposed ceiling, potentially on top of DSM charges — on generators that are curtailed for reasons of transmission infrastructure failure will: (a) erode project IRRs on already-bid PPAs; (b) undermine lender confidence; (c) increase the risk premium demanded by private capital for future RE bids; and (d) directly contradict the government's stated policy of accelerating RE deployment and ISTS charge waivers already granted to the same generators.

Merchant and RTM sales – viability at risk

Typical RTM / IEX prices for RE heavy periods are in the ₹3–₹5/kWh range, often lower in high RE seasons. If congestion charge dynamically moves between ₹3–₹10/kWh, it can equal or exceed the energy price in congested blocks.

Illustrative block (merchant sale):

- RTM sale price: ₹4.0/kWh
- Congestion charge: ₹5.0/kWh
- Net realization (before other charges): –₹1.0/kWh

In such blocks, continuing to inject power is economically irrational, pushing the IPP toward:

- Self curtailment or backing down schedules.
- Accepting zero or negative margin dispatch purely to avoid DSM/congestion instability.

For merchant heavy portfolios, this can turn previously profitable peak/shoulder windows into loss making intervals and substantially erode average realization.

Tariff volatility and bankability

RE generators already face:

- Tighter DSM bands and increasing DSM charges.
- Curtailment risk from system operators and discoms.

Adding congestion linked pricing introduces location and time specific volatility on top of market price volatility. This:

- Makes cashflows less predictable for merchant and short term OA portfolios.
- Raises lender concerns on DSCR and refinancing where merchant tail or RTM sales were key to the investment thesis.

“Economic curtailment” even without physical backing down

Even when system operators do not physically curtail, a high congestion charge can make dispatch uneconomic. RE IPPs then either:

- Withhold injection to avoid losses (“economic curtailment”), or
- Inject and accept negative or near zero margins.

From a financial perspective, this is equivalent to lowering effective PLF or CUF, because a portion of technically available generation is not monetized at positive value.

OA / C&I and group captive – margin compression

Open access and group captive RE already face a rising stack of costs (banking restrictions, additional surcharges, wheeling, and other network charges). The new congestion charges, when triggered, further narrow the spread between delivered RE tariff and consumer grid tariff.

Consequences:

- Reduced attractiveness of short term/RTM linked OA contracts.
- Lower savings for C&I consumers, making them more selective on corridor/location and contract structure.
- Group captive projects with schedule mismatch or high deviation exposure see intermittent margin wipe outs during congestion events.

Impact on EBITDA and IRR

For an RE IPP with meaningful merchant exposure, blockwise congestion events can drive:

- Average realization down from ~₹4.0/kWh to ₹2.5–₹0/kWh across affected hours, depending on congestion frequency and severity.
- EBITDA margins compressing from 60–70% into the 20% range or even negative in high stress scenarios, especially where leverage is high and O&M plus interest are relatively fixed.

At portfolio level, this can translate to IRR erosion in the order of 200–500 bps for merchant heavy or OA heavy projects, particularly in RE rich exporting states where congestion is recurrent.

Illustration:

(a) Congestion charge rate in respect of the WS Seller for a particular time block:

Type of Entity	Scheduled Injection (MW)	Actual Injection (MW)	Available Capacity (MW)	Deviation (MW)= Actual-Schedule	Deviation%	Contract Rate (in Rs./ Unit)	DSM rate (Rs./unit)	Congestion charge rate (in Rs./ Unit)
	A	B	C	D=B-A	(Actual - Schedule) / (Available capacity) $E=((B-A)/C) * 100$	F	G	1.5 times the base rate of deviation, i.e. $H=1.5 \times F$ (subject to a minimum of Rs 3/Unit and a maximum of Rs. 10/Unit)
WS Seller (Solar)	100	115	120	15	12.5%	3	90% of the Contract Rate, i.e. Rs. 2.7 Per Unit	4.5
WS Seller (Solar)	100	105	120	5	4.16%	3	Contract Rate, i.e. Rs. 3 Per Unit	4.5
WS Seller (Solar)	100	90	100	-10	-10%	3	Contract Rate, i.e. Rs. 3 Per Unit	4.5
WS Seller (Solar) merchant	100	115	120	15	12.5%	7	90 % of the Contract Rate, i.e. Rs. 6.3 Per Unit	10 (1.5*7=10.5, capped at Rs. 10)
WS Seller (Solar) merchant	100	88	100	-12	-12%	7	110 % of the Contract Rate, i.e. Rs. 7.7 Per Unit	10 (1.5*7=10.5, capped at Rs. 10)
WS Seller (Solar) merchant	100	80	100	-20	-20%	7	200 % of the Contract Rate, i.e. Rs. 14 Per Unit	10 (1.5*7=10.5, capped at Rs. 10)
WS Seller (Solar) merchant	100	80	100	-20	-20%	0.40	200 % of the Contract Rate, i.e. Rs. 0.80 Per Unit	3 (1.5*0.4=0.6, fixed at min. rate of Rs. 3)
WS Seller (Wind) merchant	100	80	100	-20	-20%	1.5	110 % of the Contract Rate, i.e. Rs. 1.65 Per Unit	3 (1.5*1.5=2.25, fixed at min. rate of Rs. 3)

Note: Congestion charges shall be payable/ receivable based on the corridor in which the congestion has been notified by the system operator and the corresponding location of the seller and the deviation by such seller (over-injection/ under-injection)

The Commission is respectfully urged to ensure that its congestion charge revision — which is technically sound in its DSM-linkage design — is not operationally deployed in a manner that penalises generators for institutional failures on the grid planning side that are well-documented, quantified, and officially acknowledged.

PART VI: CONCLUSION

Congestion in India's grid today is predominantly a **structural, infrastructure-side problem**, not a behavioural generator-side problem. The evidence is unambiguous: 50 GW stranded nationally, 2.3 TWh curtailed in 2025, transmission delays of 18–20 months on key RE evacuation corridors, and a CAG performance audit that documented systemic delays in 16 out of 18 audited PGCIL projects.

The Commission's proposed revision to the congestion charge rate — linking it to 1.5× DSM rates with a Rs. 3–10/unit band — is a reasonable technical design in isolation. However, applying it to RE generators facing involuntary curtailment due to transmission system failure, without any accountability mechanism on the planning side, creates a regulatory asymmetry

that is difficult to sustain under principles of proportionality, natural justice, and the broader statutory framework of the Electricity Act.

The Indian Wind Power Association (IWPA) respectfully submits and prays that the Hon'ble Commission:

- Commission and publish a corridor-wise structural vs. behavioural congestion attribution analysis before finalising the revised charge;
- Introduce a structural congestion suspension mechanism exempting generators from congestion charges where transmission infrastructure delays are demonstrably the proximate cause;
- Create symmetric accountability by linking CTU/STU fixed charge recovery to timely ATC achievement; and
- Ensure the revised framework does not impose dual penalties (DSM + congestion charge) on RE generators for weather-driven deviations within T-GNA constraints.

ANNEX: KEY SOURCES RELIED UPON

Source	Title / Finding	Year
CAG, Report No. 9 of 2020	Performance Audit: Planning and Implementation of Transmission Projects by PGCIL during XII Plan (2012–2017). Findings: 16/18 projects delayed; TTC 19.97%–83.66% of capacity; no network plan on record.	2020
CAG, Report for XI Plan (2014)	Performance Audit of PGCIL for 2007–2012 period. Identified planning and grid management shortfalls including congestion attribution failures.	2014
Ember Energy	Beyond Capacity: Why India's Power System Must Get Flexible (January 2026). 2.3 TWh solar curtailed May–Dec 2025; ~4 GW T-GNA solar fully curtailed on some days in December 2025.	Jan 2026
IEEFA (Vibhuti Garg, Prabhakar Sharma)	Green Power Transmission Development in India (2025). ~50 GW RE stranded nationally; 8 GW stranded in Rajasthan; transmission planning must shift to adaptive cycle.	2025
Mercom India	Rajasthan Curtails 4 GW of Solar and Wind as Transmission Delays Mount (October 2025). Up to 51.5% curtailment; NSEFI letter documenting 18–20 month transmission delays; 8.1 GW project delayed.	Oct 2025
Down To Earth	Transmission Challenges: India's Renewable Energy Projects Face Grid Hurdles (October 2025). At least 30 solar/wind plants curtailed Mar–Aug 2025; losses up to Rs 700 crore.	Oct 2025
Down To Earth	Curtailment, Transmission Bottlenecks and Storage Gaps Dominate India's Power Transition Outlook (March 2026). CEA Chairperson statement at FICCI India Energy Transition Summit, September 2025.	Mar 2026

Source	Title / Finding	Year
Outlook Business / ICRA	Transmission Gaps, Discom Delays Put a Brake on India's Green Transition (January 2026). Substation capacity 33% below target; RE awards slump to 5.8 GW in Apr–Nov 2025-26.	Jan 2026
CERC Order 1/SM/2026	Rate of Congestion Charge in Real-Time Operation in Interstate Transmission of Electricity (March 13, 2026). Document under review.	Mar 2026
CEA, National Electricity Plan Vol. II (Transmission)	Transmission planning for 2022–27 and perspective plan for 2027–32. Documents need for 123,577 ckm and 710,940 MVA additions in current plan period.	2023/24