Transmission Losses, PoC Charges and RE Scheduling in India 2026

By Sudarshan Karweer · 27 August 2026 · growthifye.com

A practitioner guide to ISTS losses, PoC charges, waivers, scheduling and project economics for RE in India in 2026.

India's renewable-energy market in 2026 is no longer constrained only by module pricing, land aggregation, or offtake structures. For utility-scale solar, wind, hybrid and storage-linked projects, transmission economics now has a direct and often material impact on tariff competitiveness, merchant realisations, banking assumptions and lender confidence. Many projects that appear viable at the busbar become significantly weaker once Inter-State Transmission System (ISTS) losses, Point of Connection (PoC) charges, waiver eligibility, scheduling obligations and deviation settlement are modelled correctly.

This article focuses on a commercial-transmission angle that is distinct from pure connectivity, substation readiness, green energy corridors or generic grid-code compliance. The key question is simple: in 2026, how should developers, C&I consumers, lenders and policymakers evaluate the combined impact of transmission losses, network charges and scheduling discipline on renewable-energy project economics in India?

Why transmission economics now matters as much as evacuation approval

Over the last few bid cycles, headline tariffs for central and state renewable tenders have remained highly sensitive to a narrow set of variables: module and inverter costs, wind turbine pricing, CUF assumptions, debt terms, and land-related delays. However, as more projects inject into congested corridors and power is sold across states to DISCOMs, traders, exchanges and open-access consumers, the delivered-cost equation has become more complex.

For an RE generator, the realised value of each injected megawatt-hour depends on:

- Whether ISTS charges are fully waived, partly waived, or payable
- The applicable transmission losses on the injection and drawal path
- Whether the project sells under a fixed-tariff PPA, FDRE structure, RTC blend, exchange route or C&I open-access model
- The accuracy of day-ahead and intra-day scheduling
- Deviation Settlement Mechanism (DSM) exposure
- Curtailment risk, especially in high-RE pockets
- The ability of storage or flexible resources to reshape injections

For buyers, especially C&I consumers, the focus is shifting from nominal landed tariff to delivered, risk-adjusted power cost. A solar-wind-hybrid contract at an apparently attractive tariff can still underperform if losses are higher than assumed, scheduling mismatch is frequent, and balancing energy is expensive.

ISTS charges and loss waivers in 2026: what developers must model carefully

India's policy framework has used ISTS charge waivers to accelerate renewable deployment, especially for solar and wind projects supplying power across state boundaries. By 2026, however, the practical issue is not merely whether a waiver exists in principle, but whether the specific project and commissioning timeline satisfy the notified conditions.

Developers should evaluate at least five points.

- Eligibility window: Waiver benefits are typically linked to bid award date, commissioning date, project type and policy notifications issued by the Ministry of Power.
- Scope of waiver: Some structures may provide waiver on transmission charges but not necessarily eliminate all operational or related liabilities in every commercial pathway.
- Phased commissioning treatment: Delays in part commissioning can alter cash-flow assumptions if benefits are linked to COD milestones.
- Hybrid and storage treatment: Co-located or integrated assets may require careful interpretation of the applicable regulations, especially where charging energy, auxiliary consumption or non-RE components are involved.
- Change-in-law claims: If a waiver assumption was embedded in a bid model, later policy or regulatory shifts can create disputes over pass-through and risk allocation.

For projects without a full effective waiver, PoC charges can materially affect landed cost. While PoC rates vary by node, season and applicable allocation framework, even a seemingly moderate transmission charge assumption can alter delivered energy economics by Rs 0.15-0.45/kWh in some structures once combined with losses and balancing costs. For merchant or short-tenor sale strategies, this is not a rounding error; it can decide whether a project consistently clears target returns.

Losses matter just as much. If a developer models 2.5% effective transmission loss but actual commercial impact trends closer to 4-5% over the sale pattern, the revenue leakage becomes significant. On a 300 MW solar project at 28% CUF, an additional 2% loss impact can mean roughly 14.7 million kWh annual reduction in delivered energy. At a realised tariff of Rs 3.20/kWh, that is about Rs 4.7 crore per year of gross revenue impact before secondary effects.

Lenders are therefore increasingly stress-testing transmission assumptions instead of relying on sponsor base cases. A credible diligence process in 2026 should include scenario modelling for waiver qualification, commissioning slippage, evolving loss factors and node-specific evacuation constraints.

RE scheduling and DSM: the underappreciated value killer

Transmission access gets a project to the grid. Scheduling discipline determines whether the project actually monetises power efficiently. This is especially relevant for wind, hybrid and merchant-linked portfolios where generation uncertainty and price volatility interact.

In India’s current market structure, scheduling is not a back-office formality. It has direct commercial consequences through deviation charges, imbalance costs, and buyer confidence. The impact is most visible in three categories.

First, stand-alone wind projects with variable generation profiles often face forecast error challenges, especially during monsoon transitions and abrupt weather events.

Second, solar projects selling partly on exchanges may overestimate the value of peak irradiance blocks if losses, congestion or revised schedules reduce actual delivered volume.

Third, hybrid projects sometimes assume that combining solar and wind automatically solves variability. In practice, the quality of forecasting, pooling arrangement, SCADA visibility and dispatch logic determine whether hybrid smoothing translates into lower penalties.

For many operating portfolios, the effective cost of poor scheduling can range from a few paise to well above Rs 0.20/kWh on affected energy blocks, depending on market conditions and deviation profile. That cost can erase the perceived edge of a more aggressive tariff bid.

This is where disciplined metering architecture, forecasting tools and operational protocols matter. Developers often focus on evacuation infrastructure capex but underinvest in telemetry, control logic and coordination between plant operator, scheduler and buyer. In 2026, that is no longer acceptable for serious portfolios.

Capabilities such as [Protection, control & SCADA](/coreservices/transmissionengineering/protectioncontrolandscada) and [Power system studies](/coreservices/transmissionengineering/powersystemstudies) are not peripheral engineering services. They directly influence whether the project can support accurate scheduling, event analysis and stable operation under changing grid conditions.

C&I open-access buyers: delivered tariff must include transmission reality

For commercial and industrial buyers procuring renewable power through inter-state or intra-state open access, transmission economics is now central to board-level energy strategy. Large consumers in data centres, automotive, steel, chemicals, FMCG, textiles and pharmaceuticals are increasingly evaluating round-the-clock or shaped renewable contracts rather than plain vanilla solar.

The usual mistake is to compare quoted generation tariff with retail DISCOM tariff without adjusting for the full delivery stack.

A proper 2026 comparison should include:

- Generator tariff or contract energy rate
- ISTS/STU transmission charges, where applicable
- Transmission and wheeling losses
- SLDC charges, scheduling and system operation costs
- Cross-subsidy surcharge and additional surcharge, if applicable under the route chosen
- Banking charges and banking settlement treatment, where permitted
- DSM or balancing cost pass-through under the PPA or supply contract
- Curtailment or must-run qualification risk

For a C&I consumer evaluating a 50 MW equivalent procurement program across multiple facilities, errors in transmission-loss assumptions can create a 3-5% gap between projected and actual delivered savings. On large annual energy volumes, that can distort procurement decisions, internal carbon-abatement claims and captive/group-captive structuring.

Buyers should also examine whether the seller's node choice creates hidden congestion exposure. Two projects with similar quoted tariffs but different injection points can have meaningfully different delivered-cost outcomes.

This is why serious open-access procurement in 2026 requires joint commercial and technical diligence. [Connectivity & open access](/coreservices/transmissionengineering/connectivityandopenaccess) strategy cannot be separated from transmission economics, scheduling capability and substation-level operational readiness.

Lender and investor lens: bankability now depends on transmission assumptions

Project finance committees in 2026 are far more alert to transmission-linked downside than they were three years ago. There are good reasons.

- Transmission commissioning delays can push COD and interest during construction higher.
- Waiver eligibility can be time-sensitive.
- Congestion can affect scheduling and dispatch confidence.
- Loss assumptions can overstate annual available saleable energy.
- In merchant or quasi-merchant structures, balancing and DSM costs can be highly variable.

For lenders, the right diligence questions include:

- Is the base-case delivered energy model based on ex-bus generation or post-loss saleable energy?
- Has the borrower separately modelled technical generation loss, transmission commercial loss and curtailment risk?
- Are scheduling penalties borne by the generator, trader, or offtaker?
- Does the PPA clearly allocate transmission-charge change risk?
- If storage is included, what is the treatment of charging energy and round-trip impact under the project's commercial structure?
- Is there a robust contingency for transmission-linked delay beyond the generator's physical plant readiness?

Debt sizing based on optimistic delivery assumptions is becoming harder to defend. For example, a 500 MW hybrid project with expected annual output of around 1.75 billion kWh may appear comfortably bankable under a fixed-tariff framework. But if actual delivered energy after losses, outages, and scheduling underperformance falls by even 4%, the revenue impact at Rs 3.50/kWh is about Rs 24.5 crore annually. In tighter DSCR structures, that is material.

Policy and regulatory priorities for 2026

Policymakers and regulators face a delicate balance. India needs rapid renewable capacity addition, but it also needs commercially disciplined grid usage and transparent cost allocation. Several priorities stand out.

First, waiver frameworks should remain clear, stable and time-bound. Uncertain extension or interpretation raises bid risk and increases financing cost.

Second, transmission-loss signalling should be transparent enough to improve locational decisions without making bid evaluation excessively speculative.

Third, DSM and scheduling rules should continue encouraging forecasting discipline, but implementation needs to reflect the operational realities of high-renewable systems, especially for hybrid and storage-coupled projects.

Fourth, market design should increasingly reward flexible delivery rather than only installed capacity. As peak demand in India continues to rise and evening ramps become sharper, projects that can shape output and reduce balancing stress deserve better commercial treatment.

Fifth, data visibility across CTU, STUs, SLDCs and market participants needs improvement. Developers and buyers still spend too much time reconciling operational assumptions across agencies and contracts.

These issues are not abstract. They influence auction outcomes, merchant confidence, interstate power flows, and the cost of decarbonisation for Indian industry.

Practical checklist for developers and buyers

Before locking bids, PPAs, open-access contracts or financing terms, stakeholders should complete a transmission-economics checklist.

- Validate waiver eligibility against current 2026 notifications and project timeline.
- Model at least three scenarios for commercial transmission loss.
- Separate busbar generation from delivered saleable energy in financial models.
- Review whether the injection node could create congestion or curtailment exposure.
- Quantify DSM risk under realistic forecasting error bands.
- Ensure metering, telemetry and scheduler coordination are bankable, not generic.
- Align contract clauses on who bears transmission-charge changes and balancing cost.
- Test whether storage, if proposed, truly improves delivered value after all losses and charges.
- Include lender-style downside cases, not only sponsor upside assumptions.

In many cases, the cheapest quoted tariff is not the cheapest delivered power. Likewise, the project with the fastest connectivity path is not always the one with the strongest long-term economics.

India's 2026 renewable market is entering a more mature phase where transmission is not just an enabling infrastructure topic. It is a core commercial variable. Sponsors that integrate engineering, regulation, scheduling and finance will price risk better, bid more intelligently and avoid avoidable erosion in realised returns.

For developers planning interstate sale, for C&I buyers comparing procurement routes, and for lenders screening bankability, the right question is no longer "Do we have connectivity?" It is "What is the true delivered cost and operational risk of using the grid over the life of the project?"

If you need support on transmission economics, scheduling risk, evacuation strategy or project diligence, contact Growthifye's advisory desk. Our teams support developers, C&I buyers, utilities and lenders across technical-commercial assessment, project structuring and execution readiness.

Explore Growthifye's related capabilities

This analysis connects directly to our advisory practice: [Power system studies](/coreservices/transmissionengineering/powersystemstudies) · [HV/EHV substation design](/coreservices/transmissionengineering/hvehvsubstationdesign) · [Transmission line engineering](/coreservices/transmissionengineering/transmissionlineengineering) · [Protection, control & SCADA](/coreservices/transmissionengineering/protectioncontrolandscada).

ABOUT THE AUTHOR

Sudarshan Karweer — Chief Executive Officer, Growthifye

Over 23 years in management consulting — concept to scale — building and scaling new-age digital and energy businesses. An EY alumnus, Sudarshan leads Growthifye's renewable energy & storage advisory, EPC, transmission engineering and green-financing practices for developers, utilities and C&I consumers across India.
Contact: info@growthifye.com · +91 84510 99371 · growthifye.com