Transmission Access for Open Access RE in India 2026: LTA, GNA, STU and Curtailment

By Sudarshan Karweer · 25 August 2026 · growthifye.com

A 2026 guide to transmission access for open access renewables in India: GNA, LTA, STU planning, charges, curtailment and lender risks.

India's renewable market in 2026 is no longer constrained only by module prices, land aggregation or DISCOM credit risk. For many open access and utility-scale projects, the decisive variable is transmission access: who grants it, on what basis, how much it costs, and whether the project can actually evacuate on schedule without sustained curtailment. For commercial and industrial buyers, developers, lenders and utilities, transmission strategy now directly affects tariff discovery, COD risk, merchant upside and debt service coverage.

This article focuses on a topic distinct from routine grid-evacuation and study discussions: the commercial and regulatory architecture of transmission access for renewable projects in India in 2026. Specifically, it examines how General Network Access (GNA), Long-Term Access (LTA), STU systems, open access approvals, transmission charges and curtailment exposure interact in practice for solar, wind, hybrid and storage-linked projects.

For project sponsors, the lesson is simple: transmission is no longer a downstream engineering workstream. It is an early-stage bankability issue.

Why transmission access has become the real bottleneck in 2026

India's installed renewable capacity has continued to expand across utility-scale solar, wind, hybrid and RTC structures, but substation readiness and transmission access remain uneven across states and renewable resource zones. Some high-irradiation and high-wind corridors offer attractive generation profiles yet face bay congestion, delayed line readiness, uncertain downstream strengthening or restricted open access windows.

At the same time, power offtake structures have become more diverse:

- captive and group captive open access
- third-party open access for C&I consumers
- inter-state sale under SECI or bilateral structures
- hybrid portfolios using firming from battery energy storage systems
- RTC and peak power products for large industrial loads

Each structure creates different transmission obligations and risk allocation. A project selling power to an intra-state C&I buyer may be primarily exposed to STU planning, state open access rules and intra-state wheeling constraints. A project serving a diversified buyer base across states may depend more heavily on ISTS access, scheduling discipline and pooling arrangements. In both cases, developers can no longer assume that transmission approvals will naturally converge with project construction timelines.

In 2026, the biggest timing mismatches usually arise from five factors:

- generation asset construction finishing before bay or line readiness
- LTA or connectivity assumptions not matching actual offtake geography

- changing open access consumer profiles after financial close
- STU augmentation lagging renewable commissioning
- curtailment and congestion reducing net delivered units below base-case estimates

For lenders, these are not abstract technical issues. Even a 3% to 7% reduction in delivered annual energy due to evacuation constraints can weaken DSCR for tightly priced projects. For merchant-exposed assets, transmission uncertainty can erase arbitrage gains that justified storage or hybrid capex in the first place.

GNA, LTA and connectivity: what developers and buyers must understand

The transition to a General Network Access framework has changed how market participants think about inter-state transmission usage. Earlier, many sponsors modelled transmission more narrowly around point-to-point access logic. In 2026, projects and procurers need a broader view of network access rights, network usage and scheduling obligations.

At a practical level, three questions matter before land and EPC packages are frozen:

- Is the project expected to inject power predominantly into the inter-state system or remain intra-state?
- Will the offtake profile remain stable for 15 to 25 years, or is buyer churn likely under open access structures?
- Is the transmission strategy being designed for physical evacuation alone, or also for commercial flexibility?

For utility-scale projects under central procurement or inter-state sale, LTA-linked planning assumptions still matter for bankability, especially where downstream system creation, pooling arrangements and substation augmentation are involved. For open access portfolios, however, many developers are discovering that commercial flexibility in offtake can conflict with transmission planning certainty.

A solar or hybrid project may secure land in a strong resource area and negotiate attractive module or turbine pricing, but if its evacuation path depends on a substation with limited spare transformation capacity or on a line package delayed by right-of-way issues, the nominal tariff can become irrelevant. In some states, developers have quoted delivered C&I tariffs in the range of about Rs 3.40 to Rs 4.50 per kWh for solar open access, and higher for hybrid or firm products, but these economics are highly sensitive to actual transmission charges, losses, banking treatment and curtailment.

For offtakers, the distinction between connectivity approval and dependable evacuation must be clearly understood. A connectivity grant or in-principle approval does not automatically mean:

- bay readiness by the project COD date
- unconstrained evacuation during peak renewable injection hours
- completed upstream strengthening works
- low transmission-loss assumptions over the PPA tenure
- immunity from state-level open access process delays

The market now rewards sponsors who map access rights, physical network readiness and commercial offtake structure together instead of in silos.

STU versus ISTS strategy for open access and utility-scale RE

One of the most consequential decisions in transmission planning is whether the project should be structured primarily around the State Transmission Utility system or the Inter-State Transmission System. The answer depends on buyer geography, state policy posture, project size, congestion outlook and expected evolution of the customer base.

An STU-led strategy may appear simpler for intra-state C&I supply because:

- wheeling distances may be lower
- state-level offtake can be aligned with local load centres
- scheduling and settlement may be operationally familiar
- some projects can avoid added complexity from inter-state interfaces

However, STU dependence can become a concentration risk if the state network is already stressed in the renewable belt or if open access processing is uneven. In several states, the practical challenge is not only line capacity but also substation transformer headroom, bay availability and downstream evacuation from pooling points. State-specific charges and procedural delays can materially change project economics after bid submission.

An ISTS-oriented strategy can offer broader marketability and multi-state offtake potential, but it is not automatically superior. Sponsors must account for:

- central transmission planning timelines
- interface readiness with generating stations and pooling substations
- scheduling and dispatch discipline across regions
- changing transmission charge treatment over time
- loss allocation and congestion risk

For large hybrid and RTC-oriented assets, the optimal structure is increasingly a portfolio view rather than a binary STU-versus-ISTS choice. Some developers are using a combination of state evacuation and inter-state market optionality to diversify buyer risk. But this only works if the project's transmission design, metering architecture, contractual provisions and system studies are aligned from the beginning.

From a lender perspective, the key issue is not whether the project sits on STU or ISTS. The key issue is whether the chosen route has credible evidence of timely readiness, stable charge assumptions and manageable curtailment risk.

Transmission charges, losses and delivered tariff math

Transmission planning mistakes usually surface first in delivered tariff calculations. Developers often discuss levelised generation cost in isolation, while C&I buyers increasingly evaluate landed power cost after all network charges, losses, cross-subsidy surcharges, additional surcharges where applicable, banking conditions and profile mismatch.

In 2026, project economics can swing materially based on transmission treatment. Even when generation tariffs are competitive, the final delivered cost may rise because of:

- transmission and wheeling charges
- transmission and wheeling losses
- scheduling and deviation implications
- state-specific open access surcharges
- curtailed energy reducing annual bill savings

- additional balancing cost for shaped or firm supply

For example, a solar open access project with an ex-bus tariff assumption near Rs 3.20 to Rs 3.60 per kWh can look highly attractive at term-sheet stage. But after adjusting for transmission losses, wheeling, open access charges and temporal mismatch with the consumer load curve, the effective savings case may narrow significantly. Hybrid projects can improve delivered-value consistency but often require higher capex and more complex transmission planning, especially where storage charging and discharging patterns affect network usage and scheduling.

This is why advisory and lender models should run at least three cases:

- base case with approved charges and normative losses
- downside case with delayed network readiness and higher losses
- stress case with recurring curtailment during high-generation months

A difference of even 1.5 to 2.5 percentage points in annual transmission loss assumptions can matter over a 20- to 25-year asset life. Likewise, recurring curtailment concentrated in the highest-irradiation months can disproportionately reduce project IRR because those months typically anchor generation output.

For industrial offtakers comparing group captive, third-party open access and utility supply, the right benchmark is not headline renewable tariff. It is the fully delivered, contract-adjusted, risk-adjusted cost per consumed unit.

Curtailment risk, congestion and what lenders now diligence

Curtailment has moved from a legal afterthought to a central credit variable. In many transactions, lenders and investors are now scrutinising the historical and projected behaviour of evacuation corridors before sanction. They want to know not only whether the project can evacuate under normal conditions, but how often generation may be restricted under peak injection, maintenance outages or regional congestion.

Curtailment can arise from multiple conditions:

- local substation overloading
- transmission line congestion
- transformer outage or derating
- delayed augmentation of upstream assets
- system security instructions during low-demand or high-RE periods
- mismatch between commissioned generation and evacuation readiness

In renewable-heavy states, a project may technically comply with grid norms and still face periodic backing down due to network saturation. Where PPAs or energy service agreements do not appropriately allocate this risk, disputes can emerge between generator, consumer and lender.

By 2026, prudent diligence for transmission-linked risk should include:

- substation-wise spare capacity verification
- bay allocation status and implementation schedule
- upstream and downstream line readiness
- historical congestion patterns in the relevant corridor
- outage planning and redundancy assessment

- state and central curtailment protocols
- contractual treatment of deemed generation, if any
- sensitivity of debt service to energy haircut scenarios

Projects in wind-rich zones deserve extra scrutiny because seasonal concentration of generation can amplify evacuation stress. Solar projects near dense renewable clusters can also face midday congestion, particularly where local demand is weak and network strengthening trails capacity addition. Hybrid and storage-linked projects can mitigate some curtailment exposure if dispatch is intelligently shaped, but that requires both system capability and market design support.

For policymakers and utilities, the signal is clear: capacity addition targets without synchronised transmission access planning can depress asset utilisation and undermine investor confidence.

A practical transmission-access checklist before bid, land close or financing

Transmission risk must be screened before major capital commitments. Too many projects still finalise land, EPC assumptions or offtake negotiations before validating realistic network access. In 2026, that sequencing is unsafe.

A practical pre-investment checklist should cover the following:

- identify exact injection point options, not just district-level assumptions
- confirm bay availability and substation augmentation schedule
- verify transformer capacity, voltage level and downstream evacuation path
- assess whether the project is best suited for STU, ISTS or a mixed strategy
- map expected buyers and likely changes in offtake geography over time
- model transmission charges, losses and curtailment in tariff scenarios
- align connectivity milestones with EPC construction schedule
- test COD sensitivity to line delays and right-of-way risks
- ensure grid studies and protection philosophy match the final evacuation scheme
- incorporate transmission-related conditions precedent into financing and PPA documents

For C&I buyers, procurement teams should ask developers more rigorous questions before signing long-tenure power contracts:

- What exact substation and voltage level will the project use?
- Is the evacuation infrastructure already operational, under construction or only planned?
- How are curtailment and transmission losses treated in billing?
- What happens if the project's access path changes after signing?
- Is the tariff still viable if open access approvals or transmission readiness slip by six months?

Developers that can answer these questions with corridor-level evidence, implementation milestones and downside modelling will command greater lender confidence and stronger buyer credibility.

What the market should expect next

Over the next 12 to 24 months, India's renewable market will increasingly differentiate between projects that merely have resource quality and projects that have secure transmission access. The premium will shift toward assets with proven evacuation readiness, flexible offtake architecture and defensible delivered tariffs.

Three trends are likely in 2026 and beyond:

- more rigorous lender diligence on substation and corridor readiness
- greater use of hybrid and storage configurations to manage evacuation and profile risk
- sharper buyer focus on delivered cost rather than quoted generation tariff

For utilities and planners, stronger coordination between generation approvals, transmission buildout and open access administration will be critical. For policymakers, market confidence will improve when connectivity, network augmentation and access-right frameworks are implemented with transparent timelines and corridor-level visibility.

For developers and C&I consumers, the conclusion is straightforward: transmission access is now a strategic procurement and financing variable, not a post-award compliance item. The winning projects in 2026 will be those that integrate grid access, commercial structure and bankability from day one.

If you are evaluating a renewable project, open access portfolio or transmission-linked financing case, contact Growthifye’s advisory desk for project-specific support on transmission strategy, connectivity pathways, grid studies, substation planning and lender-grade risk assessment.

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