Substation Bay Readiness for RE Projects in India 2026: Costs, Timelines, Risks

By Sudarshan Karweer · 27 August 2026 · growthifye.com

A practical 2026 guide to bay allocation, substation readiness, approvals, costs and delay risks for RE evacuation in India.

India's renewable build-out is no longer constrained only by modules, turbines or land. In 2026, a large share of project slippage sits at the substation interface: bay availability, line termination readiness, protection integration, SCADA mapping, and the sequence of approvals needed before first synchronisation. For developers, C&I consumers procuring open access power, lenders underwriting completion risk, and utilities managing corridor congestion, substation bay readiness has become a bankability issue, not merely an engineering checklist.

This article focuses on a specific transmission topic that is often underestimated in project planning: substation bay readiness for renewable evacuation in India. The issue cuts across ISTS and STU connectivity, central and state approvals, and both utility-scale and captive/open-access projects. It also directly affects COD declarations, deemed generation claims, IDC, liquidated damages exposure, and curtailment vulnerability in the first operating year.

Unlike broader discussions on grid codes or transmission access, bay readiness is a site-specific execution risk. A project may have connectivity in principle, land in hand, EPC awarded and financing tied up, yet still miss its evacuation window because the designated 220 kV, 400 kV or 765 kV bay is not physically ready, not protection-integrated, or not released for charging by the relevant transmission utility.

Why bay readiness is now a critical 2026 transmission issue

India's RE capacity pipeline has expanded faster than some node-level transmission assets. The result is not always system-wide shortage, but localised readiness gaps at substations and pooling points. In practice, many projects face one or more of the following:

- connectivity granted but bay not earmarked with a firm execution schedule
- bay civil works completed but primary equipment supply delayed
- GIS or AIS extension ready, but protection panels and interlocks pending
- line termination available, but revenue metering, ABT compliance or telemetry not commissioned
- bay physically charged, but no final operational clearance for injection
- common pooling infrastructure complete, but upstream transformation or downstream line not available

For lenders, these are not minor defects. A one- to four-month delay in bay readiness can materially affect DSRA assumptions, scheduled drawdown, and debt servicing in the first two quarters post-planned COD. For open access C&I transactions, delayed injection can trigger replacement power procurement at discom tariff, often in the range of Rs 6.0-9.0/kWh depending on state, versus contracted renewable landed tariffs commonly around Rs 3.2-5.5/kWh for 2026 structures after wheeling and banking adjustments.

At the utility-scale end, the cost of delayed bay readiness is often larger than the bay capex itself. Even a 100 MW solar project losing 60 days of generation around a strong irradiation window can see meaningful revenue leakage. At a CUF of 24%, 100 MW would generate roughly 14.4 million units over 25 days and about 34.6 million units over 60 days. At a tariff of Rs 2.7-3.3/kWh, that is roughly Rs 9.3-11.4 crore of gross revenue foregone over 60 days, excluding fixed O&M, IDC, and PPA delay consequences.

What exactly is included in substation bay readiness

In developer conversations, “bay available” is often used loosely. In execution terms, bay readiness should mean a much tighter set of conditions has been satisfied.

A transmission bay for an RE project may include:

- physical space allocation within an existing or greenfield substation
- approved single-line diagram and layout integration
- primary equipment such as circuit breaker, CTs, PT/CVTs, isolators, earth switches, surge arresters and structures
- control and relay panels with required protection philosophy
- communication interfaces, disturbance recorder integration and SCADA/EMS mapping
- revenue metering and ABT-compliant metering as applicable
- cable trenching, marshalling kiosk/interface works and auxiliary supply
- bus extension or bus sectionalisation works if required
- transformer bay coordination where interconnection is not line-only
- testing, charging approval and final operational handover

For 220 kV and above, the lead time is heavily influenced by equipment type and substation configuration. AIS extensions may sometimes be added faster where spare land and bus provisions exist. GIS extensions can be more compact but may face longer manufacturing and integration timelines depending on OEM and compatibility with installed switchgear.

This is why developers should not rely on “connectivity granted” as shorthand for “substation interface ready.” Proper due diligence requires engineering review, utility coordination and realistic sequencing. Growthifye’s teams often see delays emerge at the interface between [Power system studies](/coreservices/transmissionengineering/powersystemstudies) and on-ground bay implementation, especially where approved studies assume a network element that is not yet commissioned.

Typical bay capex and timeline ranges in India 2026

Actual costs vary by voltage level, utility standards, GIS versus AIS, brownfield complexity, protection architecture and who bears the upstream augmentation cost. Still, market participants need planning ranges.

Indicative 2026 capex ranges seen in the market are:

- 132 kV bay: around Rs 2.5-5 crore for basic extension scenarios, higher if significant civil or control-room augmentation is needed
- 220 kV bay: around Rs 4-8 crore in many AIS cases; higher for constrained brownfield sites or GIS integration
- 400 kV bay: often around Rs 7-15 crore depending on layout, protection, bus extension and utility specifications
- 765 kV bay: materially higher, commonly project-specific and often bundled with larger network augmentation economics

These are not universal benchmarks and should not be used for bid pricing without utility-specific validation. Costs can move upward if the project requires:

- additional bus reactors or compensation-linked interfaces
- control room extension and new relay architecture
- bay-to-bay interlocking modifications in existing live substations
- demolition/relocation inside congested brownfield assets
- dedicated telecom redundancy and wider SCADA upgrades
- revised fire protection or statutory compliance works

Timelines in 2026 typically fall in the following broad range from final design freeze to operational readiness:

- simple 132/220 kV brownfield bay additions with spare provisions: 6-9 months in best-case conditions
- more typical 220/400 kV bay works with procurement and live-substation shutdown coordination: 9-15 months
- GIS-heavy, land-constrained or multi-agency interface cases: 12-18 months or more

The biggest mistake in project scheduling is counting only equipment erection time and ignoring shutdown windows, OEM panel integration, utility witnessing, and final bay charging permissions.

Approval chain and coordination bottlenecks

Substation bay readiness sits at the intersection of commercial approvals and technical clearances. Depending on whether the project is under CTUIL/ISTS, central utility interface, or STU/state transmission networks, the process stack can involve multiple agencies.

Common coordination points include:

- connectivity grant conditions and dedicated bay allocation language
- approval of SLD, layout and interface responsibility matrix
- transmission licensee construction schedule and procurement plan
- bay ownership and O&M responsibility allocation
- protection settings approval and relay coordination
- telemetry and scheduling system readiness with SLDC/RLDC interfaces
- energy accounting and metering compliance
- shutdown approvals for tie-in works
- pre-commissioning test protocols and charging permissions

For state networks, process discipline varies significantly by state. In some states, STU and discom interface coordination is relatively mature; in others, the handoff between evacuation approval, bay execution and open access processing can become fragmented. This matters greatly for captive and group captive structures, where financing assumptions may depend on a narrow commissioning window tied to shareholder consumption planning.

A practical issue in 2026 is that many developers still execute connectivity and bay planning in silos. Legal/commercial teams pursue connectivity approvals while project teams finalise EPC packages, but the utility interface package is not tracked with the same rigor as generation BoS. This creates late discovery of missing items such as relay logic approvals, communication redundancy, or metering room readiness.

For this reason, bay readiness should be monitored through a formal milestone register, not informal utility follow-up. The register should include drawing approvals, equipment manufacturing status, civil readiness, relay panel FAT/SAT, telecom mapping, metering approval, shutdown dates and target charging date.

Key risks for developers, C&I offtakers and lenders

Substation bay delays create different risks for different stakeholders.

For developers:

- scheduled COD slips despite plant mechanical completion
- IDC and overhead escalation
- PPA milestone LD exposure
- mismatch between module/inverter warranty clock and revenue start
- temporary generation restrictions after charging due to incomplete upstream readiness

For C&I buyers under open access:

- delayed contracted supply commencement
- higher dependence on discom power during peak tariff periods
- RPO or internal decarbonisation targets slipping
- mismatch with annual energy budgeting and RE100-style procurement plans

For lenders:

- underestimated completion risk in base case model
- delayed principal repayment start if moratorium is tight
- increased drawdown pressure from prolonged project tail
- need for stronger conditions precedent tied to interconnection readiness

In credit review, lenders should ask for more than a connectivity letter. They should seek evidence of bay allocation, utility execution status, responsibility demarcation for substation works, and whether the identified substation has parallel congestion or augmentation dependencies. In merchant-exposed projects or short-tenor C&I structures, even a 90-day delay can materially reduce project IRR.

How to diligence bay readiness before financial close or EPC award

A disciplined bay-readiness diligence process can prevent most unpleasant surprises. Developers and financiers should focus on verifiable questions.

Key diligence questions include:

- Has the bay been specifically identified, or is it contingent on future augmentation?
- Is the designated substation existing, under construction, or only planned?
- Who is executing the bay and by what date under which approved package?
- Are there any upstream line, ICT, bus extension or compensation dependencies?
- Is there spare protection/control architecture, or are major modifications needed?
- What shutdown windows are required for tie-in works, and who controls them?
- Has telecom/SCADA integration with SLDC/RLDC been scoped and budgeted?

- Are there known land, litigation, forest or RoW dependencies affecting the connected line segment?
- Is there any seasonal commissioning risk due to monsoon access or heat-related outage restrictions?

The answers should feed into both the project schedule and the finance model. Where uncertainty is high, contingency should not be a token line item. For transmission interface risks, developers often need both time contingency and cost contingency.

This is also where integrated engineering support matters. A developer may have excellent generation EPC capability but still miss the substation interface details. Services such as [HV/EHV substation design](/coreservices/transmissionengineering/hvehvsubstationdesign) and [Protection, control & SCADA](/coreservices/transmissionengineering/protectioncontrolandscada) become central when the evacuation package requires close coordination with utility standards and live-network constraints.

What good practice looks like in 2026

The strongest RE developers in India now treat substation and bay readiness as a first-order project workstream from day one. Good practice includes:

- aligning connectivity, land, generation EPC and evacuation planning at bid stage
- freezing interconnection philosophy before FC rather than after EPC mobilisation
- obtaining utility-confirmed milestones for bay and associated line readiness
- conducting interface design reviews with utility, EPC, protection vendor and SCADA team together
- tracking charging prerequisites weekly in the last 120 days before target COD
- building commercial protections into PPA, TSA-equivalent and EPC contracts where feasible

Policymakers and utilities also have a role. Standardised disclosure of bay availability, augmentation status and realistic readiness timelines at major RE nodes would reduce market friction. A more transparent queue and bay-allocation visibility framework, especially on heavily subscribed state nodes, would help avoid stranded project development spending.

For India’s 2026 renewable trajectory, the lesson is straightforward: transmission readiness is not only about access rights and high-level corridor availability. It is about whether a real, commissioned, protection-integrated bay exists on the date the plant is ready to inject power.

Projects that solve this early will reach COD faster, reduce financing stress, and improve first-year generation monetisation. Projects that do not may discover too late that one incomplete bay can hold back hundreds of crores of generation assets.

If you are evaluating RE evacuation, substation interface risk, or lender-grade transmission diligence, contact Growthifye’s advisory desk. Our team supports developers, investors, utilities and C&I buyers across transmission planning, utility coordination and execution-risk review.

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).

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