# Reactive Power Planning for RE Evacuation in India 2026: ISTS, Grid Codes, Costs

By Sudarshan Karweer · 13 September 2026 · growthifye.com

*How reactive power planning affects RE evacuation in India in 2026: ISTS connectivity, grid-code compliance, sizing logic, costs and lender risks.*

India's renewable build-out in 2026 is no longer constrained only by generation economics. For many solar, wind and hybrid projects, the real bottleneck is whether power can be evacuated into the grid without voltage excursions, repeated grid-code observations, or expensive late-stage retrofits. That is why reactive power planning has moved to the centre of transmission engineering conversations.

For developers, lenders, C&I buyers sourcing through open access, utilities and policymakers, reactive power is not an academic subject. It directly affects connectivity timelines, pooling substation design, inverter operating strategy, transmission losses, delivered CUF and payment security. On interstate projects, especially those seeking ISTS connectivity under GNA-based frameworks, a weak reactive power strategy can become the reason a project misses commissioning windows or suffers avoidable generation restrictions.

This article explains how reactive power planning should be approached for RE evacuation in India in 2026, what the cost ranges typically look like, and where project teams make the most expensive mistakes.

## Why reactive power planning matters in 2026

India's grid is seeing a rising share of inverter-based resources connected across solar parks, wind clusters and hybrid corridors. These assets are efficient at active power injection, but their reactive power behaviour depends on inverter capability, plant controller logic, collector-system design, transformer tap philosophy and the strength of the upstream network.

In practical terms, reactive power planning decides whether the project can:

- hold voltage at the point of interconnection within permissible limits
- comply with connectivity conditions issued by CTUIL, STU or transmission licensees
- avoid overvoltage during low-generation and light-load periods
- maintain plant output without excessive inverter derating
- reduce the need for emergency reactor or capacitor additions after commissioning
- support stable operation in renewable energy zones and green energy corridors

Across India in 2026, this issue is especially visible in high-RE states and corridors where 220 kV, 400 kV and 765 kV systems are handling variable injections over long EHV lines. Long lines and lightly loaded systems can produce sustained high-voltage conditions due to line charging. At the same time, heavy injection pockets can pull voltages down under stressed conditions if reactive support is not located properly. The result is a planning problem that cannot be solved by a generic "add capacitor banks" approach.

## What Indian project teams actually need to plan

Reactive power planning for RE evacuation should start much earlier than many EPC schedules currently allow. It must be embedded in the connectivity strategy, not bolted on after main equipment ordering.

At a minimum, teams should evaluate:

- inverter reactive capability across the full active power range
- collector network VAR consumption at 33 kV or 66 kV level
- main transformer impedance and tap range impact
- EHV line charging and bus-voltage behaviour at the evacuation node
- seasonal operating scenarios including low-load, high-wind-night and peak-solar conditions
- nearby compensation assets such as bus reactors, line reactors, capacitor banks, SVCs or STATCOMs already planned in the corridor
- dispatch constraints caused by power-factor obligations or voltage schedules

In India, many renewable projects are still bid and costed assuming inverters will carry most of the reactive burden. That assumption is increasingly risky. Inverter nameplate capability does not always translate into usable reactive headroom at all operating points. For example, a plant expected to deliver near rated MW may see limited residual capability to absorb or generate VARs unless oversizing and control settings are planned carefully.

A common field issue in 2026 is that projects achieve trial synchronization, but then receive repeated observations around voltage control response, power factor, or inability to absorb reactive power during specific system states. That creates a cascade of consequences: fresh studies, revised plant controller settings, additional reactors or capacitor banks, outage coordination and delayed final approvals.

This is why serious developers now front-load [Power system studies](/coreservices/transmissionengineering/powersystemstudies) before finalising evacuation architecture.

## The compliance lens: ISTS, GNA and grid-code expectations

Under India’s present transmission planning and connectivity framework, RE generators connecting to ISTS or major state transmission systems are expected to demonstrate technical compatibility well before COD. Connectivity and access are increasingly tied to evidence that the project can operate within the prescribed voltage and reactive power envelope.

The exact conditions differ by connection point, utility practice and granted connectivity terms, but in 2026 project teams should assume scrutiny on the following:

- voltage regulation performance at the point of interconnection
- reactive capability and power-factor range committed by the plant
- dynamic response of the plant controller and inverter controls
- interaction with nearby compensation devices and grid controls
- compliance under normal and contingency operating scenarios
- model validation and study assumptions accepted by the concerned utility or transmission planner

For developers using the ISTS route, the commercial significance is large. If reactive planning is weak, the project can face:

- delayed bay energisation or synchronization permissions
- revised interconnection conditions that add capex late in the cycle
- reduced export during system-stress periods

- higher uncertainty in lender base-case generation assumptions
- disputes over whether the deficiency lies within the generating station or the network

The issue also matters to C&I consumers procuring renewable power through open access. A project with fragile reactive behaviour may show more curtailment or unstable scheduling performance in some corridors, indirectly affecting delivered energy and contract economics. That is why [Connectivity & open access](/coreservices/transmissionengineering/connectivityandopenaccess) assessments should not treat transmission approval as a pure paperwork track.

## Design options: inverters, capacitor banks, reactors, SVCs and hybrids

There is no universal solution for reactive power management. The right architecture depends on grid strength, voltage level, line length, inverter technology, generation profile and connection-point obligations.

In the Indian market in 2026, the main tools are:

- inverter-based reactive support from central or string inverter fleets
- fixed or switched capacitor banks
- fixed or switched shunt reactors
- dynamic VAR systems such as SVCs
- hybrid schemes combining inverters with reactors or switched banks

Inverter-based reactive support is attractive because it appears embedded in plant equipment. But it can be operationally constrained when the project is exporting at high active power, particularly if the inverter DC/AC ratio and thermal margins do not support sustained reactive dispatch. It is useful, but it should not be the only line of defence on many large projects.

Capacitor banks remain cost-effective for steady-state reactive injection needs, especially at pooling substations. Typical 33 kV or 220 kV switched-bank solutions can be economical, but they are not suitable for all dynamic conditions. They can also worsen overvoltage during light-load periods if not staged and controlled properly.

Shunt reactors are increasingly important in renewable evacuation corridors with long EHV lines. In 220 kV and 400 kV systems, fixed or switchable reactors are often necessary to absorb excess reactive power and keep bus voltages under control when generation is low or line loading is light. Many developers underbudget this requirement in early DPRs, then face unpleasant surprises during connectivity review.

Dynamic devices such as SVCs may be justified where voltage is highly variable, short-circuit strength is modest, or utility conditions are stringent. They are more expensive than fixed compensation but can avoid repeated operational restrictions. The economic question is not only capex; it is whether dynamic support saves enough generation, avoids enough curtailment and de-risks enough compliance events to be worth the spend.

## What does it cost in India in 2026?

Actual project costs vary by voltage level, OEM, control philosophy, land, bay availability and utility conditions, but practitioners can use broad 2026 ranges for initial screening.

For utility-scale RE evacuation projects in India:

- 33 kV switched capacitor banks may fall roughly in the range of Rs 0.35-0.70 crore per MVAr equivalent package depending on duty, switching scheme and integration complexity

- 220 kV capacitor-bank installations can move to around Rs 0.60-1.10 crore per MVAr when bay, protection and civil scope are included
- 220 kV shunt reactor solutions often land in a significantly higher total package range because cost depends strongly on reactor rating, bay arrangement and associated substation scope
- dynamic compensation systems at larger ratings can run into tens of crores, especially once civil works, controls, harmonic filtering, auxiliaries and testing are included

These are not bidding tariffs; they are planning-level benchmarks. The more important point is this: a late reactive power correction almost always costs more than a properly engineered one. Emergency additions after first synchronization tend to attract premium procurement pricing, outage coordination losses and lender anxiety.

There is also an energy-yield cost. If inverter reactive duty forces active power backing-down during specific operating windows, the annual generation impact can become material. Even a 0.5-1.5% avoidable generation loss can be financially meaningful on a 300 MW to 500 MW plant over the PPA term.

For lenders, the takeaway is straightforward. Reactive planning should be checked in technical due diligence not only as a compliance item but as an energy-delivery risk. Conservative sensitivity cases should ask whether the project needs additional compensation capex post-financial close.

## Common mistakes developers and EPC teams make

The first mistake is treating reactive power as a single-number requirement. In reality, the project must perform across multiple operating states. A plant that looks compliant at full-load daytime solar conditions may struggle badly at sunrise, sunset, night-time wind peaks or low-grid-demand conditions.

The second mistake is assuming the utility will solve upstream voltage problems. Transmission planners may strengthen the broader network over time, but the generator is still expected to meet its connectivity conditions at the interconnection point. Hoping that future corridor upgrades will absorb today’s design gap is not a bankable strategy.

The third mistake is poor coordination between plant design and substation design. Reactive equipment, transformer tap settings, collector cable lengths, bus configuration and controller tuning all interact. This is where integrated [HV/EHV substation design](/coreservices/transmissionengineering/hvehvsubstationdesign) becomes essential rather than optional.

The fourth mistake is relying on generic OEM capability letters instead of project-specific studies. Utility reviewers increasingly want credible, scenario-based analysis using realistic system models. A one-page statement that the inverter can operate at a target power factor is not enough for a complex ISTS-linked node.

The fifth mistake is underestimating commissioning complexity. Even if compensation hardware is installed, the sequence of testing, controller tuning, relay settings and SCADA integration affects actual field performance. Reactive assets must be visible and controllable in a way aligned with grid operator expectations.

## A practical workflow for RE evacuation projects

For Indian developers, a robust 2026 workflow should look like this:

- establish likely interconnection conditions as early as land and evacuation options are being finalised

- run preliminary load-flow and voltage studies for multiple generation and network scenarios
- compare options: inverter-led strategy, switched compensation, reactor-based absorption, or mixed architecture
- freeze transformer tap philosophy and plant controller objectives early enough to influence procurement
- validate compliance against utility-specific connectivity conditions and relevant grid-code requirements
- include realistic capex and outage assumptions in the financial model
- revisit the studies once final OEM data, line lengths and substation single-line diagrams are available
- plan commissioning tests, telemetry and operator interfaces in advance

This process sounds standard, but in practice it is still compressed or skipped on many projects racing toward award and COD milestones. That is precisely why reactive power issues persist despite mature equipment markets.

For policymakers and utilities, the policy implication is equally clear. Standardised study expectations, faster review of model assumptions, and corridor-level visibility of compensation planning can reduce uncertainty for developers while improving system performance.

## Why this is becoming a strategic issue, not a narrow engineering one

Reactive power planning now affects the entire value chain of renewable power in India. It influences whether a generator can evacuate contracted energy, whether a lender can trust output assumptions, whether a C&I buyer receives stable supply, and whether utilities can operate renewable-heavy corridors without recurring voltage-management stress.

As India pushes deeper into solar-wind-hybrid deployment and larger ISTS-linked renewable zones, the projects that perform best will be those that design evacuation holistically. That means combining generation design, substation philosophy, compensation strategy, controls and compliance evidence from the beginning.

Developers who wait for utility comments before thinking seriously about VAR support will keep paying in the form of redesign, delay and curtailment. Those who integrate studies early can often reduce lifetime cost even if the initial capex appears slightly higher.

If your project is evaluating ISTS connectivity, pooling substation scope, or a revised evacuation plan, Growthifye’s advisory desk can help with reactive power strategy, Power system studies and HV/EHV substation design. Contact Growthifye to review your compliance path, capex options and execution risks before they become commissioning delays.

## 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