Price it Right

Reforming InSTS Pricing, Building on ISTS Experience

TRANSMISSION SERIES

Prayas (Energy Group)

Price it Right:

Reforming InSTS Transmission Pricing, Building on ISTS Experience

Faizan Faiz | Saumendra Aggrawal
Ashwin Gambhir | Sreekumar Nhalur

August 2025

A Discussion Paper

Prayas (Energy Group)

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Prayas (Energy Group)
Unit III A & III B,
Devgiri, Kothrud Industrial Area,
Joshi Railway Museum Lane, Kothrud Pune 411 038.
Maharashtra
☎ +91 20 2542 0720
energy@prayaspune.org
https://energy.prayaspune.org/

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1. Context

Transmission is treated as a common carrier, implying that the transmission network must function in a non-discriminatory, open-access manner. It should provide fair and equal access to all users, including generators, distribution companies, and large consumers. A robust transmission system forms the backbone of the electricity sector, facilitating the integration of new generation capacity—particularly from emerging renewable energy sources—while enabling the effective operation of competitive electricity markets and strengthening overall grid reliability.

The enactment of the Electricity Act, 2003 (EA 2003) marked a turning point in India's power sector reform. It introduced significant structural changes, including the de-licensing of generation and the promotion of competition through open access. Crucially, the Act recognized transmission as a distinct licensed activity to be carried out in accordance with regulations framed by the respective Regulatory Commissions. Under Section 25, the Central Government is empowered to define regional boundaries and modify them as required to ensure the efficient, economical, and integrated transmission and supply of electricity. It may also designate a Government company as the Central Transmission Utility (CTU), provided that the CTU is not engaged in generation or trading. At the state level, Sections 30 and 35 direct State Commissions to regulate transmission within their jurisdiction, while State Governments may designate a State Transmission Utility (STU), similarly restricted from trading activities.[1]

In 2005, the Ministry of Power (MoP) notified the National Electricity Policy, which emphasized the need for a national transmission tariff framework that is sensitive to factors such as distance, direction, and the quantum of flow to facilitate cost-effective transmission across regions (Clause 5.3.5). The policy also advocated consistency in transmission pricing nationwide to avoid tariff pancaking, and guided State Commissions in formulating intra-State tariff frameworks.[2]

Following this, the Tariff Policy, 2006 addressed key aspects such as transmission planning, pricing, infrastructure, and loss allocation. It called for a suitable tariff framework for all inter-State transmission, including flows through intervening states, aiming to promote optimal asset utilization and accelerate new transmission capacity development (Clause 7.1). The Policy proposed approaches like per MW per circuit-kilometer, zonal postage stamp, or other pragmatic methods to ensure that users pay in proportion to their usage. Additionally, it required State Electricity Regulatory Commissions (SERCs) to adopt a similar approach for intra-State transmission within two years of implementing the inter-State framework, considering factors such as voltage, distance, direction, and quantum of flow.[3] This was reiterated in the revised Tariff Policy, 2016 (Clause 7.1(8)).[4]

In 2021, the MoP notified the Electricity (Transmission System Planning, Development and Recovery of Inter-State Transmission Charges) Rules, which stipulated that the Inter-State Transmission System (ISTS) be treated as a single integrated network. Designated ISTS users seeking General Network Access (GNA) are now required to pay both a one-time GNA charge and monthly transmission

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1. The Electricity Act, 2003.
https://cercind.gov.in/Act-with-amendment.pdf

2. National Electricity Policy, 2005.
https://powermin.gov.in/en/content/national-electricity-policy

3. Tariff Policy, 2006.
https://cea.nic.in/wp-content/uploads/legal_affairs/2020/09/Tariff%20policy.pdf

4. Revised Tariff Policy, 2016.
https://www.cercind.gov.in/2018/whatsnew/Tariff_Policy-Resolution_Dated_28012016.pdf

charges, determined by the Central Electricity Regulatory Commission (CERC) to ensure full cost recovery.[5]

India's transmission network has already seen substantial growth and is poised for further expansion, driven by rising electricity demand and planned additions to generation capacity, as outlined in Table 1 and 2. Much of the upcoming investment is focused on higher voltage levels (400 kV and 765 kV), which allow for the efficient transmission of bulk power over long distances, optimize land usage, reduce losses, and enhance system reliability.

Table 1: Transmission System Augmentation – Actual (2017-22) and Planned (2022-32)

Transmission System Aspect	2017-22	2022-27	2027-32
Transmission Lines (Ckm)	88,865	1,14,687	76,787
AC Sub-stations (MVA)	3,49,865	7,76,330	4,97,855
HVDC (MW)	14,000	1,000	32,250
Total Investment (₹ Crores)	2,54,000 (estd.)	4,25,222	4,90,920
Inter-Regional transfer capacity Expansion (MW)	37,200	30,690	24,600

Source: CEA National Electricity Plan (Volume II -Transmission), 2024 and 2019

Table 2: Transmission System Capacity Actual - (March, 2025) and Projected (March, 2032)

Transmission System Type	Total Capacity as of March, 2025	Total Capacity as of March, 2032
Transmission Lines (Ckm)	4,94,374	6,48,190
AC Sub-stations (MVA)	13,04,013	23,45,135
HVDC (MW)	33,500	66,750
Inter-Regional Expansion (MW)	1,18,740	1,67,540

Source: CEA Monthly Transmission Report for March, 2025 & CEA National Electricity Plan (Volume II -Transmission), 2024

Given that nearly two decades have passed since the articulation of these policy goals—particularly those concerning transmission pricing—it is timely to assess the progress made. This discussion paper reviews the evolution of transmission pricing frameworks for the Inter-State Transmission System (ISTS) and documents the existing practices for pricing in Intra-State Transmission System (InSTS). It concludes with suggestions for reforms to make pricing mechanisms, especially at the state level, more effective and aligned with the changing nature of the electricity sector.

This discussion paper is primarily intended for the regulatory and policy-making audience. It limits the scope to policy and regulatory aspects, and does not engage in detailed analysis of international practices or academic literature.

The discussion paper is organized into five chapters. Following this context-setting chapter, **Chapter 2** provides an overview of the key steps in the transmission process—from planning through to pricing. **Chapter 3** outlines the major changes in the ISTS pricing framework between 2002 and 2025, while **Chapter 4** presents an analysis of the methodologies adopted by different states for setting InSTS tariffs. **Chapter 5** consolidates key insights from the analysis and concludes with recommendations for improving transmission pricing across both inter- and intra-State systems.

5. Electricity Transmission Rules, 2021. https://ctuil.in/uploads/cms_documents/Electricity%20Transmission%20Rules-2021.pdf

2. Planning to Pricing

This chapter provides an overview of the existing transmission system process—from initial planning to final cost recovery. It outlines the mechanisms for project approvals, tariff discovery or determination, annual revenue recovery, and apportioning of total approved transmission costs among users. Table 3 summarizes the key steps from planning to cost recovery for both ISTS and InSTS.

Table 3: Steps from transmission planning to cost recovery

Transmission system aspects		ISTS specific details	InSTS specific details
Planning*	Short- and long-term planning based on system needs	Undertaken by CTU, CEA	Undertaken by STUs
Project / Scheme Approval	Approving Projects and recommending mode of implementation under EA Section 62 or 63	MoP, NCT, CTUIL approves projects subject to cost thresholds.	SERCs approve Transmission Investment or Capex plans. STU/Empowered Committee approves project implementation mode based on cost thresholds.
Tariff Determination or Adoption for Project / Scheme	Regulated Tariff Mechanism (RTM), i.e., cost-plus methodology under EA Section 62 where ERC determines tariffs based on prudent cost norms.	CERC determines tariff for each asset/project/ scheme after or close to CoD for the MYT period in line with tariff regulations.	No asset/project/scheme wise tariff determination.
	Tariff Based Competitive Bidding (TBCB), under EA Section 63 and Competitive Bidding Guidelines (by the Central Government).	CERC approves and adopts tariffs discovered after competitive bidding.	SERC approves and adopts tariffs discovered after competitive bidding
Regulating Transmission Licensees for RTM (section 62) projects	Approving annual recovery for each Transmission Licensee (in states) or scheme (ISTS).	No licensee wise approval of ARR; ISTS scheme wise approval by CERC.	SERC approves ARR for each InSTS licensee for MYT period or annually
Tariff determination for Transmission System Users	Apportioning the approved annual recovery among Transmission System Users.	Based on load flow studies and in line with CERC Sharing Regulations, Grid-India determines monthly transmission charges for Designated ISTS Consumers (DICs)	SERC determines transmission charges for system users based on tariff regulations and approved ARRs.

Source: Prayas analysis based on EA 2003, CERC and State MYT Regulations, CEA Transmission Planning Manual and National Electricity Plan (Transmission).

*While the CTU was made into an independent company in 2021 to undertake planning and all other related functions, the current institutional setup in states, wherein the STU and SLDC is still part of the transmission licensee limits independent and rigorous planning.

2.1. Planning

Transmission planning is a structured process to identify, evaluate, and develop infrastructure necessary for the reliable, secure, and cost-effective transfer of electricity from generation to consumption centers. The need for transmission addition may arise from increased generation or demand, as well as system-strengthening requirements to maintain grid reliability.[6]

The transmission system is divided into ISTS and InSTS networks. Planning at each level involves coordination among various agencies and stakeholders, including but not limited to the Central Electricity Authority (CEA) and Central Transmission Utility (CTU) for ISTS, and State Transmission Utilities (STUs) for InSTS. The EA 2003, National Electricity Policy, and Tariff Policy outline the roles and responsibilities of CEA, CTU, and STUs in the transmission planning process. For further detail, refer to CEA's *Manual on Transmission Planning Criteria*[7] and Chapter 2 of *the National Electricity Plan (NEP) (Transmission)*.[8]

2.2. Project/Scheme Approvals

For approving ISTS schemes, the Central Transmission Utility of India Ltd. (CTUIL) consults Regional Power Committees (RPCs) and submits expansion proposals to the National Committee on Transmission (NCT) for their consideration. Depending on the estimated project cost, the responsibility for approving schemes and their mode of implementation is shared amongst MoP, NCT and the CTUIL as detailed in Table 4.

Table 4: ISTS Schemes cost thresholds and approving authority

Cost Threshold (₹ Crore)	Approving Authority	RPC Consultation
> 500	NCT recommends to MoP for approval	Required
100-500	Approved by NCT along with mode of implementation; under intimation to MoP	Not Required
< 100	Approved by CTUIL along with mode of implementation; under intimation to NCT & MoP	

Source: Ministry of Power[9]

For InSTS schemes under section 62 (RTM), SERCs only approve investment (Capex and Capitalization) plans. Given that the statutory function of transmission system plan development is vested with the STU, presently there is no method or process for the SERC to approve the overall system plan. For InSTS schemes under section 63 (TBCB), the STU or a State Empowered Committee (in some states) approves the mode of project implementation based on cost thresholds. For more details on state wise TBCB cost thresholds, see Table 5.

6. CEA National Electricity Plan (NEP) (Transmission), 2024. https://cea.nic.in/wp-content/uploads/psp___a_i/2025/02/NEP_Vol_II_Transmission.pdf
7. CEA Manual on Transmission Planning Criteria, 2025. https://cea.nic.in/wp- content/uploads/psp___a_ii/2025/01/Manual_on_Transmission_Planning_Criteria_with_Amendment_I_2025.pdf
8. CEA National Electricity Plan (NEP) (Transmission), 2024. https://cea.nic.in/wp-content/uploads/psp___a_i/2025/02/NEP_Vol_II_Transmission.pdf
9. Re-constitution of the National Committee on Transmission (NCT), 2021. https://powermin.gov.in/sites/default/files/webform/notices/Re_constitution_of_the_National_Committee_on_Transmission_reg.pdf

Table 5: TBCB Cost Thresholds for InSTS by State

States	InSTS TBCB Threshold (₹ cr)
Madhya Pradesh	400
Telangana	300
Punjab, Haryana, Rajasthan, Gujarat, Karnataka, Andhra Pradesh, Chhattisgarh, West Bengal, Assam	250
Maharashtra, Tamil Nadu	200
Jharkhand	175
Odisha, Bihar, Uttarakhand	100
Goa, Himachal Pradesh	75
Uttar Pradesh*	220 kV

Note: *Uttar Pradesh is the only state which has set the TBCB threshold on a voltage level and not on cost. For more information, please see www.indiatransmission.org[10]

2.3. Transmission Tariffs

Once a transmission scheme is approved, it may be implemented through one of two mechanisms:

Tariff-Based Competitive Bidding (TBCB) – Section 63 of the EA 2003

In this case, the tariff is not determined directly by the Regulatory Commission. Instead, it is discovered through a transparent competitive bidding process, conducted in line with guidelines issued by the Central Government. Once a winning bidder is selected and the associated tariff is identified, the concerned Regulatory Commission—CERC for ISTS or SERCs for InSTS—reviews the bidding process to ensure compliance with applicable guidelines and regulatory norms and then formally adopts and approves the discovered tariff. In such cases, both CERC and SERCs approve scheme-wise tariffs and issue scheme/project-specific transmission licenses.

Regulated Tariff Mechanism (RTM) – Section 62 of the EA 2003

Under this route, the concerned Electricity Regulatory Commission determines the applicable tariff using a cost-plus approach, based on prudential norms and detailed cost submissions by the transmission licensee.

- For ISTS projects, CERC determines tariffs for each individual Project/Scheme, typically after or close to the Commercial Operation Date (CoD), for the duration of the applicable Multi-Year Tariff (MYT) period, in line with its transmission tariff regulations.
- For InSTS projects, SERCs do not determine project-wise tariffs. Instead, SERCs approve the aggregate Annual Revenue Requirement (ARR) for each state transmission licensee, which includes the cost of all RTM projects under its scope.

10. TBCB threshold in states.
https://indiatransmission.org/Commercial/TBCB%20Threshold%20in%20states

To determine the tariff under section 62, both the CERC (for each ISTS RTM Scheme) and SERCs (for each state licensee) periodically formulate the transmission tariff regulations for the respective entities. These regulations specify that the Annual Fixed Cost (AFC) of the transmission Scheme/ Licensee (as the case maybe) shall include the following components:

a. Return on equity;
b. Interest on loan and working capital;
c. Depreciation
d. Operation and maintenance expenses.

In the case of InSTS transmission licensees, these components together constitute the Gross ARR. To arrive at the Net ARR, several adjustments are made:

a. Non-Tariff Income to be subtracted;
b. Income from other business (e.g., Revenue from ISTS) to be subtracted;
c. Revenue Gap (if any) with carrying cost to be added;
d. Revenue surplus with holding cost to be subtracted;
e. Estimated Income from STOA to be subtracted;
f. Other adjustments (if any).

Transmission charges are typically recovered from drawee users or DISCOMs. However, in case state transmission system is being used by generators for wheeling power outside the state or by merchant generators, transmission charges are then recovered from such generators. (e.g. in Maharashtra / Rajasthan). This is particularly important as it may lead to sub-optimal network development if such charges are not recovered from these generators as these charges cannot be levied on entities outside the SERC jurisdiction.

For ISTS schemes developed under RTM, non-tariff net income from sources such as land rent or buildings, eco-tourism, sale of scrap, and advertisements is shared equally between the licensee and the beneficiaries, as per prevailing regulatory norms.[11] Similarly revenue received from the short-term customers is deducted while determining annual transmission charges payable by a long-term customer.[12]

To summarize, the Net ARR for transmission—whether for ISTS RTM schemes or InSTS licensees—represents the total annual revenue required to recover costs and earn a reasonable return. Transmission licensees file their tariff petitions with the appropriate Regulatory Commission annually or at the beginning of the control period in case of MYT. Such petitions provide comprehensive financial data and justification for their proposed costs and returns. After a due public consultation process:

- CERC approves the tariff for each ISTS RTM scheme for the MYT period.
- SERCs approve the ARR for each InSTS transmission licensee, covering all schemes under its jurisdiction.

11. CERC MYT Regulations, 2024. https://www.cercind.gov.in/regulations/notification-2024.pdf

12. CERC Open access inter-state Regulations, 2004. https://cercind.gov.in/regulation/14-GZ.pdf

2.4. Transmission Pricing for Transmission System Users

Transmission pricing refers to the process of allocating the total approved transmission cost of a system (ISTS or InSTS) among its users—typically DISCOMs, Open Access consumers, and in some cases, generators—in some proportion to their use of the system. Transmission tariffs are single-part tariffs, comprising only a fixed component (AFC) without any variable or energy-linked component. A transmission licensee recovers the transmission charges from two broad categories of transmission system users:

- Long-Term Users: Entities that have been granted access to the transmission system for seven years or more. Transmission charges are levied in ₹/MW/month or ₹/MW/day, based on contracted capacity.
- Short-Term Users: Entities using the system for a shorter duration (as brief as few time blocks or a day or one month). Charges are levied in ₹/kWh and linked to energy drawn.

Step 1: Determining Total Costs

The first step in transmission pricing is to determine the total annual costs to be recovered for building and maintaining the network. These costs include contributions from both:

- RTM projects (Section 62) and
- TBCB projects (Section 63)

Although the pricing approach differs between ISTS and InSTS, both systems incorporate the costs of all commissioned transmission projects under their purview.

A. InSTS Pricing

In most states, SERCs first pool the ARRs of all InSTS transmission licensees, including both RTM and TBCB projects, to compute the Total Transmission System Cost (TTSC) for the year.

- For RTM projects, the ARR is determined at an aggregate level for all projects under a given licensee.
- TBCB tariffs, once adopted by the SERC, are added to this cost pool.

InSTS charges are determined for the entire year and the TTSC and capacity is updated during the control period (usually 3–5 years) as new lines are commissioned or decommissioned. Charges are then re-determined for the remaining duration of the control period to reflect changes in capacity and costs. This dynamic updating process is already being followed by MERC (Maharashtra) and has been adopted by UPERC (Uttar Pradesh) in its 2025 tariff regulations.[13]

B. ISTS Pricing

In contrast to the InSTS approach, CERC does not pool RTM projects or approve licensee-level ARRs for ISTS transmission licensees. Instead:

- The Yearly Transmission Cost (YTC) of the ISTS system is calculated as the sum of annual tariffs of all individual RTM and TBCB schemes.
- ISTS charges are determined on a monthly basis.
- As new schemes become operational or capacity changes, the YTC and network capacity used for pricing are updated every month, providing high responsiveness and cost-reflectiveness.

13. UPERC MYT (Transmission) Regulations, 2025. https://www.uperc.org/Notified_User.aspx

Step 2: Allocating Costs to Users

Once total system costs are determined, they must be allocated among users. The allocation methodology is defined by the relevant tariff regulations:

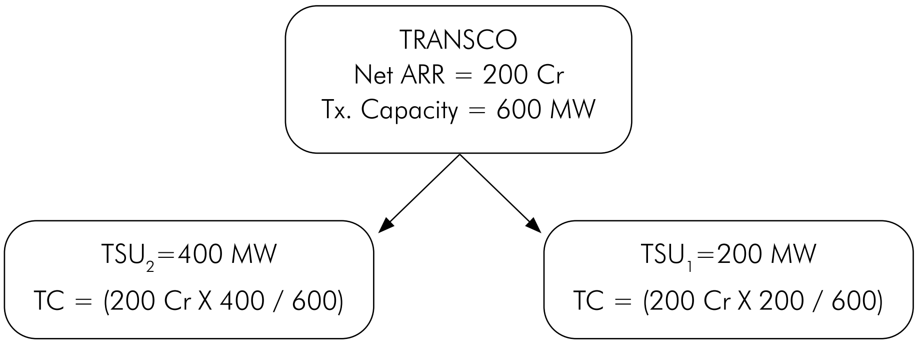
InSTS Pricing Allocation

All SERCs currently use an access-based cost allocation approach, wherein the approved pooled TTSC of the InSTS is apportioned among users (DISCOMs, Open Access consumers, generators) based on their contracted transmission capacity. This approach is often referred to as the postage stamp method, which assigns costs proportionally without considering physical distance or usage pattern. Details of state-specific allocation methodologies as specified in their tariff regulations are provided in Table 18.

Sharing of InSTS Transmission Charges

For example, if an Intra-state transmission licensee has a transmission capacity of 600 MW and an approved Net ARR of 200 Cr, with two transmission users TSU_1 and TSU_2. TSU_1 holds transmission capacity rights for 200 MW, while TSU_2 holds transmission capacity rights for 400 MW. The Net ARR of the transmission licensee is shared amongst these two transmission systems users as shown below.

Figure 1: Sharing of InSTS Transmission Charges

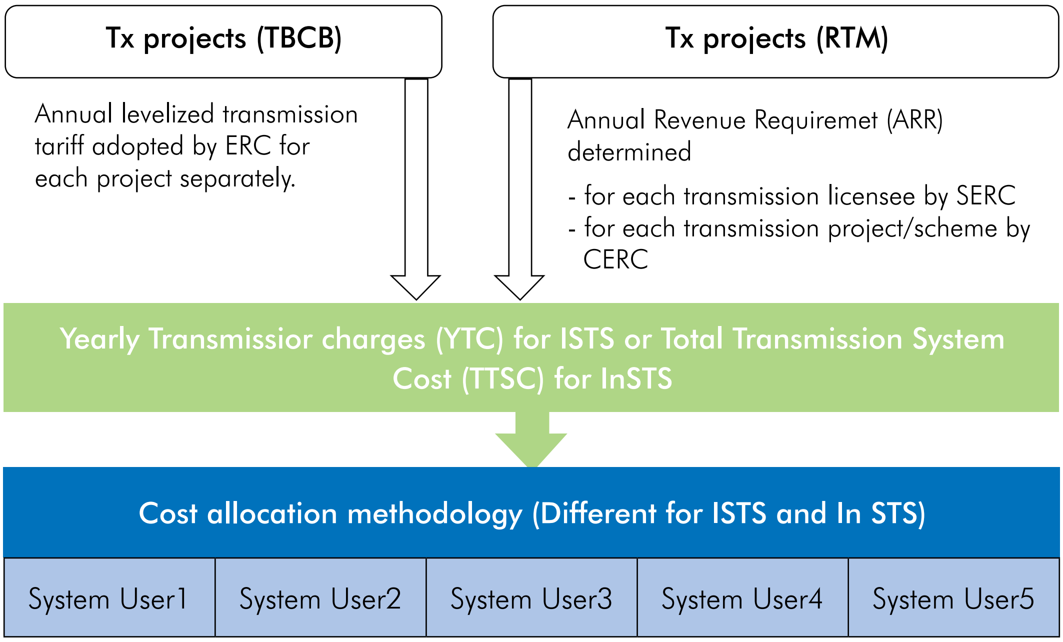


ISTS Pricing Allocation

For ISTS, the total YTC is allocated among Designated Inter-State Consumers (DICs). A part of it is apportioned based on utilisation (usage) of transmission lines by DICs while the remaining is allocated based on their General Network Access (GNA). The actual usage-based monthly charges for each DIC are determined by Grid-India using load flow studies, as per the CERC Sharing Regulations. The process ensures that users are charged in proportion to their network usage and contracted capacity on a dynamic, monthly basis.

An indicative process flow for transmission pricing for ISTS and InSTS is shown in Figure 2.

Figure 2: Pricing Framework for ISTS and InSTS systems



The next chapter provides a detailed examination of how these pricing methodologies have evolved over time for ISTS systems.

3. Reforms in ISTS Transmission Pricing Mechanism

The transmission pricing mechanism for the ISTS has evolved significantly over time, transitioning from a relatively simple and uniform method to a more complex and equitable cost allocation approach. This evolution has been driven by the EA 2003, key policy instruments such as the National Electricity Plan (Transmission), Tariff Policy, and the ISTS RE waiver; regulatory reforms including General Network Access; the maturing open access framework; the introduction of Tariff-Based Competitive Bidding (TBCB); rising private sector participation in transmission development; and the increasing complexity of India's power sector. This section traces the development of ISTS transmission pricing over time. It is structured in two parts: the first covers long-term charges, and the second addresses short-term charges.

3.1. Long-term Charges

3.1.1. Usage (Energy Scheduled) based Pricing (1991 – 2004)

Prior to the 1990s, transmission charges were not levied separately.[14] Instead, they were bundled into the generator's charges, reflecting the vertically integrated structure of the electricity sector at the time. During the 1990s, as generation and transmission functions were unbundled, the pricing mechanism evolved from implicit bundling to explicit recovery. The central transmission network was underdeveloped and lacked a robust, nationwide infrastructure. Power transfers within regions largely relied on intra-state and a few inter-state links, with no formal mechanism for recovering the cost of using another entity's transmission system. As a result, an ad-hoc practice emerged where utilities informally allowed access to their networks. This highlighted the need for a standardized and transparent system for charging for such usage. Thus, the concept of wheeling charges—fees paid by one utility to another for using its transmission infrastructure—was introduced.[15]

Charges were apportioned among transmission system users based on usage, defined as net energy scheduled during the month. This methodology favoured users who imported and exported power at different times in the same month, as charges were based on net withdrawal. Such users had to incur lower charges. Conversely, consumers with only imports incurred higher charges.[16] At this time, transmission tariffs were levied at the regional level. To maintain uniform pricing for Central Sector generation across all State Electricity Boards (SEBs) within a region, a common energy-based transmission rate (paise/kWh) was applied, regardless of the SEB's location. This rate was derived by dividing the total annual transmission system cost by the annual generation from Central Sector stations, resulting in a flat energy-based rate.

In 2001, this approach was refined further. Instead of net withdrawal, the charges were based on energy purchased by each beneficiary, as per the formula below:

14. https://posoco.in/IA/FAQ_final.pdf

15. Subrata Mukhopadhyay, Swarnamay Mukherjee, Sushil Kumar Soonee, S.S Barpanda: Wheeling Charges in Eastern Region, 1994.
https://www.researchgate.net/publication/329990354_Wheeling_Charges_in_Eastern_Region

16. S.K Soonee, S.S. Barpanda, Mohit Joshi, Nripen Mishra: Article on Point of Connection Transmission Pricing in International Journal of Emerging Electric Power Systems in India, 2013.
https://www.researchgate.net/publication/270795456_Point_of_Connection_Transmission_Pricing_in_India

$$\text{Transmission Charge} = \frac{TC}{12} \times \frac{EB}{ES}$$

Where,

- TC: Annual Transmission Charges payable by the beneficiaries.
- EB: Monthly energy sale from Central Sector Stations to each beneficiary individually as per Regional Energy Account.
- ES: Total monthly energy sale from Central Sector Stations.[17]

Despite its advantage of simplicity, this energy-based approach faced criticism. A 1994 study titled "*Study of Bulk Power and Transmission Tariffs and Transmission Regulations*" identified several limitations:

- It lacked meaningful economic signals, failing to reflect actual cost implications of electricity consumption or location-based usage for both existing and prospective system users.
- It did not consider parameters such as line or system availability or other performance metrics.
- Being a single-part tariff, it contributed to distortions in merit order dispatch.
- It increased the risk of revenue mismatch, leading to under- or over-recovery.

Finally, this rate design was incompatible with the evolving requirements of a market-oriented transmission framework.[18]

Another landmark in this period was the Shankar Guruswamy Committee (Committee of Experts Constituted to Suggest Guidelines Regarding Private Investment in Transmission Projects) report,[19] which recommended, among other things, that:

- Private transmission developers be selected through competitive bidding, with annual transmission charges as the bid parameter.
- Transmission charges should be linked to system availability, laying the foundation for availability-based pricing framework in the future.

In response to these limitations, the energy-based approach was replaced in 2004 by an access-based model, which is described in the next section.

3.1.2. Regional Postage Stamp Method (2004-2010)

In 2004, the CERC transitioned to an access-based transmission pricing model, known as the Regional Postage Stamp method.[20] In this framework, transmission charges were allocated based on the quantum of contracted capacity (MW), rather than energy drawn. Under this method:

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17. CERC Tariff Regulations 2001.
https://cercind.gov.in/tariiff/notification.pdf

18. The 1994 Report on the 'Study of bulk power and transmission tariffs and transmission regulations' by GoI and ADB in cooperation with the World Bank.

19. 19th Report of the Standing Committee on Energy.
https://sansad.in/ls/committee/departmentally-related-standing-committees/9-Energy-nameH=%E0%A4%8A%E0%A4%B0%E0%A5%8D%E0%A4%9C%E0%A4%BE

20. CERC Tariff Regulations 2004.
https://www.cercind.gov.in/regulation/16-GZ.pdf

- The long-term transmission charges were determined by dividing the annual transmission costs (aggregated for all ISTS licensees in a region) by the transmission capacity.
- Transmission charge recovery was linked to availability and normative availability was fixed at 98% for full recovery of charges in AC systems.
- Transmission charges were recovered in ₹/MW/day or ₹/MW/month from long-term users.
- Transmission charges of ISTS in a region were pooled and shared among the transmission system users who were charged a flat rate per MW for network access within a specific region.

However, as shown in Table 6, the long-term transmission charges (in ₹/MW/month) were different for intra-regional and inter-regional transactions for the period of 2004 to 2010.[21, 22]

Table 6: Intra and Inter regional differences in ISTS long-term pricing framework from 2004-2010

<table>
<tr><th>Region</th><th>2004-2006</th><th>2006-2009</th><th>2009-2010</th></tr>
<tr><td>Intra-region</td><td colspan="2">$[\sum_{i=1}^{n}\left(\frac{TCi}{12}\right) - TRSC] \times [CL/SCL]$</td><td rowspan="2">Pooled transmission cost for all components of ISTS in the region is shared among all regional beneficiaries in proportion to the sum of their respective entitlements.

Beneficiaries in other regions having entitlements in any generating station in the concerned region is shared in proportion to the sum of their respective entitlements.</td></tr>
<tr><td>Inter-region</td><td>$0.5 \times [(\frac{TCj}{12}) - RSCj] \times [CL/SCL]$</td><td>$\frac{TSC}{12} \times \frac{CC}{CIR}$</td></tr>
</table>

Source: PEG Compilation based on various CERC Tariff Regulations

Where,

TCi: Annual Transmission Charges for the i^{th} project in the region.

TCj: Annual Transmission Charges for the particular inter-regional asset connected to the region.

TSC: Annual Transmission Charges for the inter-regional asset.

TRSC: Total recovery of transmission charges for the month from Short-term transmission customers for the regional transmission system.

RSCj: Recovery of Transmission Charges for the month from the short-term customers for the particular inter-regional asset connected to the region.

21. CERC Tariff Regulations 2004 (First Amendment). https://cercind.gov.in/050606/notification.pdf

22. CERC Tariff Regulations 2009. https://cercind.gov.in/2009/Whats-New/tariff-pdf/CERC-(Terms-and-Conditions-of-Tariff)-Regulations-2009-14.pdf

CL: Allotted Transmission Capacity to the long-term transmission customer

SCL: Sum of the Allotted Transmission Capacities to all the long-term transmission customers of the regional transmission system.

CC: Capacity in MW of the inter-regional asset required for transferring allocated and/or contracted power

CIR: Capacity of the inter-regional asset in MW.

Shortcomings of the Regional Postage Stamp Model:

- Since the postage stamp method only considered the quantum (MW) of power flow, charges were independent of distance or direction, so for the same quantum of power, two users in the same region paid the same amount regardless of how far they were from the generator. Ideally, transmission system users located closer to the generators should be charged less than those located farther away.
- For inter-regional transactions (injection in one region and withdrawal in another region), regional postage charges of both regions were applicable leading to pancaking of charges.
- The model failed to reflect actual network usage, creating inefficiencies and distortions in transmission cost allocation.

As the transmission system expanded and the role of central sector generation grew, the application of wheeling charges in the ISTS became increasingly complex and these charges were discontinued with the introduction of the Point of Connection (PoC) mechanism in 2011.

3.1.3. Point of Connection (PoC) Method (2011-2020)

The PoC pricing mechanism aimed to align transmission charges with actual usage by factoring in the quantum, direction, and distance of power flow. To begin with, charges were computed based on the location of injecting and drawee entities points, thereby reflecting the extent of network utilisation by each user. PoC nodal transmission charges were determined for all DICs using load flow (See Box 1) analysis carried out by the implementing agency, Grid-India. This analysis used a hybrid methodology combining average and marginal participation methods and relied on both the ISTS network configuration and the Yearly Transmission Charges (YTC) of ISTS licensees (See Box 2). These nodal rates were then aggregated for nodes that were geographically and electrically contiguous into zones. While generation zones included nodes with similar charge ranges, demand zones generally corresponded to state control areas, except in the North Eastern Region, where all states were grouped as one zone.

Until 2015, the PoC rate for each zone (as shown below) was composed of two components:

1. A uniform charge, based on approved injection/demand and line-wise YTC.
2. A zonal charge, calculated as the weighted average of nodal charges at each node within the zone.

$$\text{PoC Rate (PoC)} = m \times \text{Uniform charge} + n \times \text{Zonal charge}$$

Where m and n were constants specified in the regulations (initially set at 50% each for the first two years of implementation, but retained until 2015). PoC charges were denominated in ₹/MW/month for long-term customers and recovered on a monthly basis while for short-term open access transactions approved by the relevant load dispatch centre, they were denominated in ₹/MW/hour.[23] Until 2015, PoC withdrawal and injection rates were specified in 3 slabs.

Uniform charges were initially introduced for two years to ease the transition and avoid tariff shocks, but they unfairly benefited entities drawing more than their entitlements and led to cost socialization—requiring users to pay for assets they didn't use. Consequently, with the introduction of third amendment to Sharing Regulations in 2015, uniform charges were phased out in favour of a usage-based framework for transmission charges.

This amendment also ensured that sharing of transmission charges was commensurate with usage close to maximum actual usage. This was made possible through changes such as:

- *Calculation of charges on* ***only withdrawal nodes*** *and for generators with LTA to target region,*
- *Shift from average (energy based) base case to maximum injection/drawal based base case,*
- *Removal of uniform charge,*
- *Spreading number of slabs from three to nine,*
- *Elimination of truncation of network, and*
- *Off set of transmission charges commensurate to STOA transactions in any region.*[24]

Consequently, the entire YTC of the ISTS network was now recovered through three components, namely:

- PoC charges
- *HVDC transmission charges*
- *Reliability S*upport Charges (RSC)

Box 1: What is a Load Flow Study?

A load flow study is a computational method used to determine power flows, voltages, and losses across a transmission network under steady-state conditions. It uses data on node/sub-station-wise injections and withdrawals; Network topology and Line parameters.

Such studies assess loading on lines, voltage profiles, and losses, and are conducted under various loading scenarios (peak/off-peak, contingencies (outage of one or more elements)). Such studies provide the foundation for network planning. In transmission pricing, load flow results provide a basis for network usage assessment and tariff design.

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23. POSOCO Procedure for Computation of Point of Connection (PoC) Transmission Charges, 2011. https://posoco.in/IA/Approved%20Procedures/Procedure%20for%20Computation_Final.pdf
24. CERC (Sharing of Inter State Transmission Charges and Losses) (Third Amendment) Regulations, 2015. https://cercind.gov.in/2015/whatsnew/SOR28.pdf

Box 2: What is Hybrid Methodology for Transmission Pricing?

The utilisation of the transmission network can be thought of in terms of average or marginal usage. Based on either measure, one can estimate how much power flows through each of the lines in the system due to the existence of each network user. The marginal participation method measures how network flows change with a small increase or decrease in injection/withdrawal at each node. The average participation method first traces physical paths for power flow for each generator and load. *'In order to create such physical paths, a basic criterion is adopted: A rule allocates responsibility for the costs of actual flows on various lines from sources to sinks according to a simple allocation rule, in which inflows are distributed proportionally between the outflows.'*

The hybrid method combines the Average Participation and Marginal Participation method *'where the slack buses are selected by using the Average Participation Method and the burden of transmission charges or losses on each node is computed using the Marginal Participation Method'*. This hybrid method is found to be more appropriate since it has a lower variance in its access charges compared to the average participation method and because it is better able to capture utilisation compared to the average participation method. For more details, refer to **Annexure I of CERC Sharing Regulations, 2010**[25] **and 2020.**[26]

The PoC charges, computed using this hybrid methodology, better captured actual utilization of network elements. In the case of HVDC systems developed to serve specific regions, transmission charges were levied on:

- DICs in the concerned region (based on approved withdrawal)
- Injection DICs with long-term access to the target region

Of the total monthly HVDC transmission charges, 10% was allocated as Reliability Support Charges (RSC). This RSC, accounting for only 10% of the overall YTC, was calculated separately and paid by all the DICs and injecting entities with LTA to the target region, proportionate to their approved withdrawal or injection.[27]

Under the PoC framework during this period, no differentiation was made between long-term, medium-term, and short-term DICs for pricing purposes. All market participants connected at the same point paid the same charge, fostering equal access and reducing entry barriers, especially for smaller entities.[28] In summary, the PoC pricing mechanism:

- Aligned tariffs with actual network usage
- Eliminated regional pancaking (See Box 3 for a brief description of pancaking).

25. CERC (Sharing of inter-State Transmission Charges and Losses) Regulations, 2010. https://www.cercind.gov.in/regulation/72-GZ.pdf
26. CERC (Sharing of inter-State Transmission Charges and Losses) Regulations, 2020. https://cercind.gov.in/2020/regulation/158-Gaz.pdf
27. CERC (Sharing of Inter State Transmission Charges and Losses) (Third Amendment) Regulations, 2015. https://www.cercind.gov.in/2015/regulation/Poc%206.4.2015.pdf
28. CERC (Sharing of inter-State Transmission Charges and Losses) Regulations, 2010. https://www.cercind.gov.in/regulation/72-GZ.pdf

- Promoted open access, competition, and market integration
- Enabled more efficient transmission investment and usage decisions

Box 3: What is pancaking and how does PoC mechanism address inter-regional pancaking for ISTS?

Pancaking refers to the accumulation of multiple transmission charges as electricity flows through different systems/regions, each levying its own charge. This increases the delivered cost of electricity and discourages inter-regional trade. Under the PoC mechanism, each participant pays a single unified charge applied at the point of connection, regardless of the path electricity takes. This eliminates multiple regional charges, thereby promoting more efficient electricity markets and enhancing open access.

3.1.4. Modified PoC (2020 onwards)

Although the PoC pricing mechanism initially fulfilled the objectives of the Tariff Policy broadly, several stakeholders expressed concerns that transmission charges were not always allocated in proportion to 'actual' utilization of transmission assets. To address these concerns, CERC constituted a Task Force chaired by Shri A.S. Bakshi (Member, Technical, CERC) to review the existing PoC mechanism. The Bakshi Task Force submitted its report in March 2019, concluding that the PoC framework had largely met the Tariff policy goals—considering distance, direction, and flow quantity. However, it also noted that the present methodology did not fully reflect 'actual' network usage as the flow across transmission lines is influenced by temporal variations in generation and load (considered for load flow studies).[29]

For instance:

- Generators do not always operate at full rated capacity.
- Beneficiary demand fluctuates across time (daily/monthly/seasonal).
- The transmission system is planned for generator's installed capacity, but this may not be fully utilized at all times.

These factors lead to partial utilisation of the transmission system.

The Task Force recommended that:

- A portion of transmission charges be allocated based on actual usage of transmission lines, determined through load flow studies.
- The remaining charges— arising from the inherent characteristics of the transmission system (e.g.; planning redundancy) and varying load-generation scenarios —be allocated among all users in proportion to their contracted capacity (Long-Term Access or Medium-Term Open Access).

Following this, CERC established a committee, chaired by Shri I.S. Jha (Member, Technical, CERC), in May 2019 to examine the Bakshi Taskforce recommendations and suggest modifications to the existing PoC framework. The committee proposed that while determining the mechanism for sharing the transmission charges by different ISTS users, the methodology should consider:

29. Report of Task Force to Review Framework of Point of Connection (PoC) Charges, 2019. https://www.cercind.gov.in/2019/draft_reg/POC%20Report.pdf

- Combining both capacity/quantum of long-term access granted and actual utilisation of elements determined through load flow studies, based on actual power system data.
- Allocating some portion of the charges based on the intended objective of the transmission element. For instance:
  - o Elements planned for the entire grid should be paid for by all users.
  - o Elements intended for specific regions should be only paid by users in those regions.
  - o Assets such as transformers dedicated to specific users should have costs allocated only to those users.[30]

These recommendations culminated in the CERC (Sharing of Inter-State Transmission Charges and Losses) Regulations, 2020, which introduced a modified PoC mechanism. Under this mechanism, long-term and medium-term transmission charges are recovered through the following components as shown in the Table 7. Prior to the implementation of the GNA regulations in 2023, the National component, Regional Component, Transformer Component and AC-Balance Component were allocated proportionally based on the quantum of Long-term Access (LTA) plus Medium-term Open Access from all drawee ISTS users, and untied LTA from injecting ISTS users, expressed in terms of ₹ crore/month. After the implementation of GNA, these components were allocated on the basis of GNA. The AC usage-based component was determined using the same hybrid method through load flow analysis.[31]

Table 7: Components of ISTS long-term Charges

No	Tariff Components		Sharing Mechanism
1	National Component	Renewable Energy (RE)	Shared by all drawee ISTS users and injecting ISTS users with untied LTA.
		High Voltage Direct Current (HVDC)	
2	Regional Component	High Voltage Direct Current (HVDC)	Shared by drawee ISTS users of the receiving region and injecting ISTS users with untied LTA in the receiving region.
		Critical Transmission elements for providing stability, reliability, and resilience in the grid.	
3	Transformer Component		Shared by the drawee ISTS users located in the concerned State.
4	AC Component	Usage Based Component	Shared by drawee ISTS users and injecting ISTS users with untied LTA corresponding to their respective usage of the transmission lines.
		Balance Component	Shared by all drawee ISTS users and injecting ISTS users with untied LTA.

Source: Compiled by PEG from CERC (Sharing of Inter-State Transmission Charges and Losses) Regulations, 2020

30. Report of the Committee to finalize draft regulations for Sharing of ISTS charges under Member (I.S. Jha), 2019. https://cercind.gov.in/2019/draft_reg/Annexure%20II_3_Dec.pdf
31. CERC (Sharing of Inter-State Transmission Charges and Losses) Regulations, 2020. https://www.cercind.gov.in/2020/regulation/158-Gaz.pdf

From 2010-20, PoC rates were specified only in a few slabs. While this simplified the process, such a slab system distorts locational signals and does not accurately reflect actual transmission usage, especially given seasonal variations across DICs. With increased availability of computational capacity, managing individual PoC charges for all DICs was feasible. Hence, the modified PoC mechanism eliminated slab-wise rates and charged each DICs separately.[32]

Box 4: Evolution of non-discriminatory Transmission Access

The evolution of India's transmission sector mirrors its broader transition from a state-controlled, vertically integrated system to a more open, competitive, and market-based structure.

Before the EA 2003, the power sector was dominated by vertically integrated State Electricity Boards (SEBs) which controlled generation, transmission, and distribution. Transmission access was limited, with negligible scope for third-party sales or cross-border trades.

The EA 2003 introduced the principle of open access, designating the CTU and State STUs as the entities responsible for providing non-discriminatory access. This reform:

- Enabled third-party sales and power trading.
- Encouraged private sector entry into generation and distribution.
- Allowed large consumers to procure power from generators of their choice.

Open access was categorized as:

Time Period	2009-2016	2017-2023	October 2023 onwards
Long-term Access	Greater than 12 years and less than 25 years	Greater than 7 years	GNA (up to or greater than 1 year)
Medium-term Access	Greater than 3 months and less than 3 years	Greater than equal to 3 months and less than 5 years	Abolished
Short-term Access	Up to one month at a time		T-GNA (one block to 11 months)

Despite these reforms, challenges persisted. The process of obtaining connectivity and access became increasingly complex due to the multiple types of access (LTOA, MTOA, STOA), each with its own procedures and timelines. Developers often faced delays, and under-utilization of transmission capacity became a concern. The disjointed nature of connectivity and access approval also led to inefficient grid planning and uncertainty in project execution. To address these challenges and streamline the access regime, a major reform in the form of General Network Access (GNA) was introduced.

General Network Access (GNA) Framework

The GNA framework, introduced in October 2023, consolidated all previous access types into a single, unified, flexible mechanism. Under GNA:

32. CERC Explanatory Memorandum to CERC (Sharing of Inter State Transmission Charges and Losses) (Third Amendment) Regulations, 2015.
https://cercind.gov.in/2014/draft_reg/Expl_memo7_2.pdf

- Entities (generators, DISCOMs, large consumers) declare capacity (in MW) for injection or withdrawal from ISTS without specifying the destination or source in advance.
- Transmission rights are decoupled from physical routes, reflecting real-world power flow determined by overall system dynamics.

GNA refers to non-discriminatory access (open access) to the ISTS, which as a transmission service, provides more flexibility and the possibility of open access to the buyers and sellers of power in terms of scheduling, subject to grid constraints. GNA enables scheduling flexibility and more efficient system utilisation. GNA_{RE} is the GNA to procure power only from the sources eligible for waiver such as Renewable Energy Generating Stations (REGS) or Renewable Hybrid Generating Station (RHGS) based on wind or solar sources, Energy storage system (ESS) such as batteries, charged with energy sourced from REGS or RHGS or generation based on hydro power sources. As a result, long-term transmission charges are recovered from the users based on their share of GNA and GNA_{RE}.

The PoC mechanism partially supported transmission decoupling from physical or contractual paths, by eliminating strict point-to-point charges and introducing zonal pricing, thereby streamlining calculation of charges. The *'PoC tariff system eliminates the complexities associated with determining which specific line(s) a user is utilising and the associated charges, significantly simplifying the process'*.[33] The GNA framework fully operationalizes route decoupling, offering uniform, flexible, and non-discriminatory access to the ISTS network based solely on capacity, without route dependence. Under this mechanism, users such as generators and consumers are granted access to the ISTS based on their declared capacity (in MW), without specifying the physical route or transmission corridor through which the power will flow. *'This approach acknowledges electricity as a fungible commodity, which means it is not traceable to a specific source upon entering the grid. Users inject and withdraw power at designated points, and the flow patterns are determined by the overall system dynamics.'*

Box 5: Treatment of losses

Until 2010, transmission losses for ISTS were calculated on a regional basis. With the implementation of the PoC mechanism (2011-2020), the computation shifted to the zonal level. Post-2020, they are calculated at the national level, ensuring uniform treatment across all entities.

- Losses are treated "in kind": Instead of monetary compensation, more energy is injected into the grid to account for technical losses, ensuring the receiving entity receives the scheduled quantity.
- For example, if 100 MWh is scheduled and 3% is the declared loss, ~103 [=100/(100-3%)] MWh must be injected.
- Losses are applied on scheduled energy, not on actual flow. However, actual flows of preceding week are used to compute national loss percentages.

33. Transmission is crucial for the energy transition – Planning, Access & Pricing in India - Views of S.K. Soonee. https://powerline.net.in/2024/03/20/views-of-s-k-soonee-transmission-is-crucial-for-the-energy-transition-planning-access-pricing-in-india/

3.1.5. ISTS waiver for RE

Policy levers as powerful as pricing rules: While the preceding sub-sections trace the technical evolution of long-term ISTS charge-sharing, from postage-stamp to PoC to the modified PoC/GNA regime, an equally significant influence has come from *policy-driven exemptions*. Since 2010, the MoP and CERC have periodically waived ISTS charges (and, earlier, losses) for RE projects to accelerate solar and wind-led capacity growth. The waiver lowers the landed cost of ISTS connected RE and has helped reduce costs for ~ 38 GW of RE so far. At the same time, because DICs buying power from these RE generators do not contribute to the PoC cost pool, the unpaid share is re-allocated across all DICs (in proportion to their non-RE drawal from ISTS), partly diluting the cost-reflective signals the PoC framework was designed to send. Understanding how this waiver evolved and *how* its scope has expanded—and is now being tapered—therefore becomes essential to appraising today's transmission-pricing debate.

In the early years of renewable energy (RE) development in India, projects were incentivized through benefits such as Accelerated Depreciation (AD) for wind and Generation-Based Incentives (GBI) for solar. Another key measure was introduced by CERC via the 2010 Sharing Regulations, which, along with its third amendment, granted ISTS transmission charge and loss waivers for solar generation projects commissioned between 1st January 2010 and 30th June 2017. This initiative aimed to promote ISTS-level solar connectivity.

The Tariff Policy of 2016, under Clause 6.4(6), further reinforced this by stating:

"In order to further encourage renewable sources of energy, no inter-State transmission charges and losses may be levied till such period as may be notified by the Central Government on transmission of the electricity generated from solar and wind sources of energy through the interstate transmission system for sale." This was later clarified by a MoP order in September 2016.

Initially, the waiver periods were:

- Wind: up to 31st March 2019 and Solar: up to 30th June 2017

Subsequently, the waiver was extended for both sources to 30th June 2025, although the waiver on ISTS losses was withdrawn. Over time, the scope of the waiver expanded to include:

- Solar-wind hybrids (with/without storage) – in Aug 2020
- Battery Energy Storage Systems (BESS) and Pumped Storage Projects (PSP) – in June 2021
- Power traded via GTAM/GDAM – in June 2021
- Green Hydrogen and derivatives – in Nov 2021 and April 2023
- Large Hydro Projects – in Dec 2022

The waiver is now set to phase out gradually from 100% to 0% between 2025 and 2028. Most recently, in June 2025, MoP extended the waiver for:

- PSP projects whose construction work awarded till 30th June 2028
- Co-located BESS projects commissioned by 30th June 2028

Earlier these projects had the waiver until 30th June, 2025. Post-June 2028, these projects will be subject to 100% ISTS charges. The CERC considers MoP waiver notifications in framing its regulations and determining ISTS charges. An overview of the existing RE waiver framework for various sources adopted by CERC is given in Table 8 and 9. For more details of how the ISTS RE waiver is calculated and accounted for while determining ISTS charges, please see Annexure III of the 1st amendment to the 2020 Sharing regulations.[34]

Table 8: ISTS waiver for RE sources

Sources	Number of years of COD	On or before 30.6.2025	1.7.2025 to 30.6.2026	1.7.2026 to 30.6.2027	1.7.2027 to 30.6.2028	After 30.6.2028
REGS based on wind or solar source or RHGS based wind and solar source, which are commissioned	25 years	100%	75%	50%	25%	0%
Hydro PSP ESS, for which construction work has been awarded	25 years	100%	100%	100%	100%	
Battery ESS connected at a substation where REGS is connected and is charged from such REGS, which are commissioned	12 years	100%	100%	100%	100%	
Battery ESS connected at a substation where no REGS is connected or Battery ESS connected at a substation where REGS is connected but Battery ESS is charged from Grid or source other than REGS or any other battery ESS not covered above, which are commissioned	12 years	100%	75%	50%	25%	0%
Hydro generating station with date of signing of PPA and award of construction work. 1) 100% waiver if date of signing of PPA and award of construction work on or after 1.12.2022 and on or before 30.6.2025. 2) The date for eligibility for waiver shall be considered as of the date of signing of the PPA or award of construction work, whichever is later.	18 years	100%	75%	50%	25%	0%
Solar PV generating station under SECI manufacturing linked capacity scheme	25 years	100%	100%	100%	100%	100%

34. CERC (Sharing of ISTS charges and losses) (1st Amendment), Regulation 2023. https://cercind.gov.in/Regulations/177-Amendment.pdf

Table 9: ISTS waiver for RE sources

Sources	Number of years of COD	Up to 31.12.2030	01.01.2031 to 31.12.2031	01.01.2032 to 31.12.2032	01.01.2033 to 31.12.2033	01.01.2034 to 31.12.2034	01.01.2035 to 31.12.2035	After 31.12.2035
REGS based on Offshore Wind, which are commissioned	25 years	100%	100%	100%	75%	50%	25%	0%
Green Hydrogen or Green Ammonia Plant as a drawee DIC, which are commissioned. As a drawee DIC, a Green Hydrogen or Green Ammonia Plant having drawal schedule from (i) REGS or RHGS based on wind (including off shore wind) or solar source, (ii) ESS which is meeting at least 51% of its annual electricity requirement for pumping of water or charging of battery with electricity generated from REGS or RHGS based on wind or solar source and (iii) Hydro generating station, shall be eligible to waiver.	25 years	100%	75%	50%	25%	0%	0%	0%

Source: PEG compilation from CERC Sharing Regulation 2020 and its amendments.

Apart from changing eligibility criteria for the ISTS waiver, the method of accounting has also evolved over the years. The waiver was initially provided based on the share of capacity of eligible RE sources contracted in the total capacity contracted at the ISTS level. However, with first amendment to CERC Sharing regulation 2020 being effective from 1st October, 2023, the waiver accounting method has changed significantly, and now is linked to the share of RE drawal in total ISTS drawal by the drawee entity. This share is calculated for each time block of 15-min and then averaged monthly to come up with a monthly waiver % for a drawee entity. This has led to a significant reduction in the waiver quantum per MW of RE. Regardless of the methodology, the RE waiver simply shifts the foregone ISTS charges onto all the DICs, making it a de-facto cross-subsidy.

Finally, this waiver has facilitated significant capacity additions (38.6 GW as of May 2025).[35] Further, as of 31 March 2025, 145 GW (79 GW solar, 27 GW wind, 39 GW hybrid) of RE capacity is in the pipeline (under construction and under bidding).[36] 153 GW of RE projects (including PSP and hydro) have been approved by CTU for ISTS connectivity, forming 93% of all applications (~163 GW total).[37]

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35. CEA Renewable Project Monitoring Division, Daily Renewable Generation Report (All India). https://cea.nic.in/wp-content/uploads/daily_reports/31_May_2025_Daily_RE_Generation_Report.pdf

36. Quarterly Report on Under-construction Renewable Energy Projects March-2025. https://cea.nic.in/quarterly-report/?lang=en

37. Connectivity Granted under GNA. https://indiatransmission.org/pages/connectivity-granted-under-gna

3.2. Short-term ISTS Charges

Short-term ISTS transmission charges were first introduced in 2004 to support the EA 2003's objectives of open access and competitive markets. Previously, transmission charges were primarily levied for long-term usage through bilateral agreements. To operationalize short-term access, there was a need for a separate, transparent, and standardized method to charge users accessing the grid on a short-term basis. The CERC brought these charges into effect to regulate and facilitate short-term access to the grid, supporting market-based power trading and ensuring cost recovery for transmission utilities. Key phases of evolution include:

2004 to 2005: ST transmission charges were introduced with the notification of the Open Access Regulations in 2004[38] and were computed as:

$$ST - Rate = 0.25 \times \frac{TSC}{(Avg.Capacity \times 365)}$$

Where:

- **ST-RATE** is the short-term open access rate in ₹/MW/day.
- **TSC** refers to the Annual Transmission Charges of the transmission licensee for the previous financial year, as determined by the Appropriate Commission.
- **Avg. Capacity** denotes the average capacity (in MW) served by the transmission system of the licensee in the previous financial year. It includes the total generating capacities connected to the transmission system and the contracted capacities of other transactions handled by the licensee's system.

This rate (ST-RATE) was applied across the regional systems, inter-regional links, and the networks of State Transmission Utilities, State Electricity Boards, or any other transmission licensees forming part of the inter-state transmission system.

2005-2008: Subsequently in 2005, under the first Amendment to the Open Access Regulations, 2004, the methodology for calculating ST transmission charges was revised as follows:

(a) For Intra-Regional Systems (same as before):

$$ST - Rate = 0.25 \times \frac{TSC}{Avg.Capacity \times 365}$$

(b) For Inter-Regional Systems:

$$ST - Rate = 0.5 \times \frac{TSC}{CIR \times 365}$$

38. CERC Open access Regulations, 2004. https://www.cercind.gov.in/regulation/14-GZ.pdf

Where CIR stands for the transmission capacity (in MW) of the inter-regional system.

2008-2010: Further, with the notification of the Open Access Regulations, 2008 and its amendment in 2009, the ST transmission charges were levied based on the energy approved for transmission at the point(s) of injection and were fixed as follows:

Table 10: ISTS short-term Charges from 2008-10

Type of transaction	**Regions**	**OA, 2008**	**OA, 2009**
		Units in ₹/MWh	
Bilateral	Intra-regional	30	80
	Between adjacent regions	60	160
	Wheeling through one or more intervening regions	90	240
Collective		30	100

Further, the ISTS entities using InSTS network were also required to pay short-term transmission charges for the use of the state network, as determined by the respective SERC. However, if the SERC has not specified such charges, the charges for using the respective state network shall be payable at the applicable rate for the approved energy, as indicated below:

Table 11: ISTS short-term Charges for use of intra-state network in case charges not determined by SERC

OA, 2008	₹ 30/MWh
OA, 2009	₹ 80 /MWh

2011-2020: For this period, there was no differentiation between PoC charges for long-term, medium-term and short-term. With the 3rd amendment to the Sharing Regulations, an additional component in the form of reliability support charge was added to the ST charge which was paid both, by the drawee and injecting entities.

2020 - Oct 2023: There was no differentiation between long-term and short-term PoC charges. The ST transmission charges were calculated state-wise on a monthly basis as below:

Short-term transmission charge (₹/MWh) =

$$\frac{\text{(Long-term Transmission charges calculated for that month for that state)}}{\text{(Quantum of LTA plus MTA of the State for the corresponding month (MW)} \times \text{No. of hours in a month (i.e.,720))}}$$

After the notification of the GNA regulations in October 2023, short-term access was replaced by temporary GNA (T-GNA). The short-term transmission charges for all drawee DICs located in the state, for the corresponding billing period are recovered in terms of T-GNA rate (₹/ MW/block) as:[39]

39. CERC (Sharing of Inter-State Transmission Charges and Losses) (First Amendment) Regulations, 2023. https://www.cercind.gov.in/Regulations/177-GAZ.pdf

T-GNA Rate (₹/MW/Block) =

$$\frac{(\text{GNA charges for all drawee DICs in the state for the billing month} \times 1.10)}{(\text{Number of days in a month} \times 96 \times \{\text{GNA and GNA-RE quantum (MW)}\})}$$

T-GNA allows the entities flexibility to schedule power for any period from one time block up to eleven months in order to manage the variations of drawal. To disincentivize excessive reliance on T-GNA, the rate has been kept higher by 10% compared to that of long-term charges.

Since the entire ISTS system cost is being recovered from DICs with long-term GNA, the additional revenue from T-GNA needs to be adjusted over time. These T-GNA and T-GNA_{RE} charges are therefore reimbursed to the drawee DICs in proportion to their share in the first bill in the following billing month, after adjustment of the amount of RE waiver for each drawee DICs.

3.3. Observations

3.3.1. Comparing various Long-Term ISTS pricing frameworks over time

Table 12 presents a comparison of different ISTS pricing mechanisms adopted over time. It outlines the key parameters considered under each mechanism for determining transmission charges and identifies the responsible paying entities.

The transition from the postage stamp method to the PoC mechanism, and more recently to the GNA framework, represents a significant progression toward meeting the objectives laid out in the National Electricity Policy. These reforms aim to enhance fairness, efficiency, and cost-effectiveness in the pricing of ISTS transmission services.

The postage stamp mechanism was simple and straightforward. It allocated costs solely based on the contracted or drawn quantum of power, without considering actual usage patterns such as direction, distance, or extent of utilization. Pricing lacked granularity and was region-specific and uniform within a region, which often led to cross-subsidization between high- and low-utilization participants. Inter-regional transactions resulted in pancaking of charges, as users had to pay tariffs for each region crossed.

Many of these shortcomings were addressed through the introduction of the PoC mechanism, which incorporated direction- and distance-sensitive pricing, along with a partial usage-based allocation of transmission costs which better reflected the actual impact of various entities on the transmission system. Under PoC, charges were based not only on contracted quantum but also on where and how electricity flowed through the grid. This made the cost allocation more equitable and reflective of actual system usage.

Table 12: Comparison across various long-term ISTS pricing mechanisms

LT Pricing Mechanism		Postage Stamp	PoC	Modified PoC	Modified PoC with GNA
Period		2002-2010	2011-2020	2020-2023	Oct-2023 onwards
Parameters considered	**Quantum**	Y	Y	Y	Y
	Direction	N	Y	Y	Y
	Distance	N	Y	Y	Y
	Usage	N	Y	Y	Y
			Partial Usage Based	Partial Usage Based (AC-usage component); specific to extent of actual utilization of transmission line.	
Components of the charge		No components	2011-15 (uniform and zonal charge); 2015-2020 (PoC, HVDC and Reliability Support Charges)	National, Regional, Transformer and AC Components	
Granularity of Pricing		Regional	Zonal, specified in slabs	DIC wise	
Frequency of determining and recovering charges		Determined annually, recovered monthly	Determined quarterly, recovered monthly	Determined and recovered monthly	
Who will pay?		Drawee Entity	Injecting and Drawee entity (2011-15); Only Drawee Entity (2015-20)	Drawee Entity, Injecting entity for only untied LTA	Drawee Entity
Units		₹/MW/Month	₹/MW/Month	₹ Crores	₹ Crores

Source: Prayas (Energy Group) compilation based on various CERC Sharing regulations and Task Force Reports.

The major changes in the PoC pricing framework post 2020 were as follows

a. The number of tariff components increased from three (PoC, HVDC, and Reliability Support Charges) to four (National, Regional, Transformer, and AC components).

b. For the part of the tariff based on LTA/GNA quantum (MW) and not linked to usage, transmission elements were assigned to different components based on their intended objective.

c. The relative share of the charges linked to actual usage has decreased.

d. PoC charges shifted from being aggregated at a few slabs to being determined for different zones (akin to states).

e. The GNA framework redefined the cost recovery structure by shifting responsibility almost entirely to drawee entities, as opposed to the earlier model, which had shared this responsibility between injecting and drawee entities.

f. Prior to 2020, transmission charges were determined quarterly and recovered monthly. Since 2020, both determination and recovery have been on a monthly cycle.

Tables 13 and 14 show how long-term and short-term charges have shifted across five representative states between 2013 and 2024.

Table 13: LT ISTS charges for 5 States with different pricing mechanisms (2011-2024)

Long-Term ISTS charges in ₹/MW/month					
States	**Jul-13**	**Jul-16**	**Jul-19**	**Jul-21**	**Jul-24**
Uttar Pradesh	2,19,088	3,25,238	3,87,415	3,76,092	3,60,461
Maharashtra	2,19,088	3,78,623	4,46,099	3,78,303	3,29,285
West Bengal	1,89,088	2,45,865	3,53,658	3,21,910	3,80,249
Assam	2,04,088	3,78,623	4,46,129	2,95,561	2,91,205
Andhra Pradesh	1,92,317	3,88,012	4,99,089	4,62,585	3,33,842

Table 13 tracks monthly LT charges (₹/MW) for Uttar Pradesh, Maharashtra, West Bengal, Assam and Andhra Pradesh at five snapshots—July 2013, 2016, 2019, 2021 and 2024. The sequence neatly maps onto the major policy shifts discussed earlier: from the initial PoC era (2013 & 2016) through the "Modified PoC" years (2019 & 2021) to the first full year of the GNA framework (2024). There is a plateau or slight decline after 2021, most evident for Uttar Pradesh and Maharashtra because of a reallocation of a larger share of common network costs to all drawee entities, moderating charges for some states. These movements illustrate how design tweaks, in addition to absolute network cost growth, drive LT tariffs. Table 14 presents the equivalent ST tariffs, expressed in paise/kWh for 2013-21 and in ₹/MW/block (with kWh equivalents shown) from late-2023 onward, when CERC switched the billing unit.

Table 14: ST ISTS charges for 5 States with different pricing mechanisms (2011-2024)

Short-Term ISTS charges in paise/kWh except for July 24 (₹/MW/Block)						
States	**Jul-13**	**Jul-16**	**Jul-19**	**Jul-21**	**Jul-24**	
	paise/kWh				**₹/MW/Block**	**equivalent p/kWh**
Uttar Pradesh	26.26	29.14	42.68	49.91	132.88	53.15
Maharashtra	26.26	34.09	46.88	51.93	121.7	48.68
West Bengal	22.26	26.66	42.68	44.15	140.55	56.22
Assam	24.26	34.09	46.88	40.38	107.64	43.06
Andhra Pradesh	22.63	34.09	51.09	63.40	123.40	49.36

Source: Prayas (Energy Group) compilation based on various CERC and Grid-India ISTS Transmission charges documents.

Note: For LT charges in July 2013, we have assumed that power is being procured from a generator located in Madhya Pradesh. ST charges were calculated by adding the ST PoC charges applicable to the respective drawee states along with the ST PoC injection charges for the injecting state, i.e., Madhya Pradesh. For July 2016 and 2019, the ST reliability support charges were included for both injection as well as withdrawal. From October, 2023, ST charges were specified in ₹/MW/block.

With the rollout of the modified PoC mechanism, and subsequently the GNA framework, the focus has increasingly shifted toward aligning transmission charges with the actual utilization of transmission assets. However, while the methodology for determining usage has evolved, the share of the total transmission charge linked to usage (i.e., AC usage-based component) has declined over time in comparison to earlier frameworks as seen in Table 15. This is primarily because while deciding the charges for all components based on LTA/GNA quantum (except AC-usage base) the objective of the transmission element or system is accounted for.[40] This does make the costs more reflective of the intended objective of the transmission elements.

Table 15: Changing share of usage based component of the LT transmission tariff

Time period	2011-2015		2015-2020		2021-2025	2021	2022	2023	2024	2025
Share of Charge linked to usage	Zonal	**50%**	PoC	**~80%**	AC- Usage based	**25%**	**26%**	**24%**	**24%**	**23%**
Share of charge not linked to usage, i.e. uniform component		**50%**		**~20%**		**75%**	**74%**	**76%**	**76%**	**77%**
Breakup of non-usage, i.e. uniform component	Uniform	50%	Reliability	~12%	AC - Balance Component	54%	51%	47%	46%	45%
			HVDC	~8%	National Component	8%	10%	14%	15%	17%
					Regional Component	8%	8%	11%	10%	10%
					Transformer Component	5%	5%	5%	5%	5%

Source: Prayas (Energy Group) compilation based on various CERC and Grid-India documents. Values for 2021 to 2025 are for the months of March in those years.

3.3.2. Calculation of short-term transmission charges

Typically, short-term transmission charges are expected to be higher than long-term charges. However, prior to the GNA regulations, the methodology used to calculate ST charges (as described in Section 3.2) resulted in equal charges for both ST and LT usage between 2011 and 2023. It was only after the 2023 amendment that ST transmission charges, under the Temporary GNA (T-GNA) framework, were explicitly set 10% higher than the applicable LT charges to discourage over-reliance on short-term access.

40. *"For example, if some system or element has been planned keeping in view entire grid, tariff of same should be shared by all the DICs of the grid. If they are planned for the benefit of a particular region, same should be shared by DICs of particular region. In case of transformers which are basically planned to supply to individual DICs, such DIC should share the tariff for it." Excerpt from Jha Committee report.*
https://www.cercind.gov.in/2019/draft_reg/Annexure%20II_3_Dec.pdf

Table 16: Comparison across various short-term ISTS pricing mechanisms

ST Pricing Mechanism	2005-2008	2008-2011	2011-2020	2020-2023	2023 onwards
Parameters considered	Average Capacity	Energy Approved	Energy Scheduled	LTOA+MTOA in MWs*	GNA
Denomination	₹/MW/Day	₹/MWh			₹/MW/Block
Comparison with LT Charges	Equal	Fixed Slabs	Equal		Higher
Differentiation between inter and intra-regional transactions.	Yes		No		
Who pays?	Short-term customer**	Applicant#	Injecting and Drawee entities	Drawee Entities	

Source: Prayas (Energy Group) compilation based on various CERC and Grid-India documents.

Notes: * MTOA/LTOA in MWs converted to energy scheduled in MWh; ** CERC Open access Regulations, 2004; # CERC Open access Regulations, 2008.

The next chapter documents the existing transmission pricing framework being followed for InSTS.

4. Transmission Pricing for intra-state entities

This section provides an overview of the transmission pricing mechanisms adopted by states for intra-state entities, the methodologies used for the calculation of long-term and short-term charges, and a comparison across states. Intra-state transmission pricing is governed by the regulations notified by the SERCs, which are responsible for determining tariffs for InSTS operating within their respective jurisdictions. All SERCs follow an access-based methodology, where the total pooled annual transmission cost of the InSTS network as approved by the SERC is apportioned among users based on their respective transmission capacity. This method is commonly referred to as the postage stamp approach.

Long-term transmission charges are recovered from users based on the estimated transmission capacity (in MW) for the specific year, using the formula:

$$\textbf{Long-term Transmission Charges to be recovered} = \frac{\textbf{(Net ARR (InSTS) or Pooled Cost (InSTS)}}{\textbf{Transmission Capacity}}$$

These charges are recovered in terms of ₹/MW/day or ₹/MW/month.

Short-term transmission charges, on the other hand, are recovered based on the estimated energy (in kWh) wheeled over the transmission system for the year, using the formula:

$$\textbf{Long-term Transmission Charges to be recovered} = \frac{\textbf{(Net ARR (InSTS) or Pooled Cost (InSTS)}}{\textbf{Energy Transmitted}}$$

These charges are recovered in terms of ₹/kWh.

Table 17 below illustrates the calculation of long-term and short-term transmission charges respectively, for a representative transmission licensee with Net ARR of ₹ 5,000 crores, a transmission capacity of 25,000 MW, and transmitting 150,000 MUs of energy in a year.

Table 17: Illustrative calculation of Long-term and Short-term Transmission Charges

Net ARR	Transmission Capacity	Annual Energy Transmitted	Long-term transmission charge	Short-term transmission charge
(₹ Crore)	(MW)	(MUs)	(₹/MW/Month)	(₹/kWh)
A	B	C	(A×10^7)/(12×B)	(A×10^7)/(CX10^6)
5,000	25,000	1,50,000	1,66,667	0.33

4.1. Composite Tariffs or Pooled ARRs

For states with a single transmission licensee, the application of the postage stamp method is straightforward. However, in states with multiple transmission licensees, accurately determining usage and network allocation across users requires detailed load flow studies, which are currently not undertaken in any state.

To address this, some states have adopted a composite transmission charge mechanism, or pooled ARR mechanism, where the Annual Revenue Requirements (ARRs) of all transmission licensees are combined to form the Total Transmission System Cost (TTSC) of the InSTS system. This pooled cost includes both Regulated Tariff Mechanism (RTM) and Tariff-Based Competitive Bidding (TBCB) projects. Specifically for RTM projects, the ARR is determined at the aggregate level for all projects combined for each licensee. Similarly, the transmission capacities of all system users (long-term and medium-term) are combined as aggregated Transmission Capacity Rights (TCRs). Transmission charges are then calculated by dividing the TTSC by the aggregated TCRs and apportioned in proportion to their TCR.

Since InSTS charges are determined for the entire year, as new InSTS lines are commissioned, the TTSC and TCRs are updated for the remainder of the control period, and charges are recalculated. This approach is currently followed by MERC and has also been recently adopted by UPERC in its 2025 tariff regulations.[41]

However, this approach results in socialization of costs. All users share the transmission costs of every licensee, regardless of whether they use or are connected to a particular network. See Box 6 for an example from Maharashtra.

Box 6: Maharashtra and Mumbai - Socializing some Transmission costs

Mumbai region has an islanding scheme since 1981, designed to isolate the city from the rest of the Western Grid in the event of major disturbances.[42] In case of islanding, the city must rely on the generation within the greater Mumbai region. Initially, when the Western Grid was weaker and less reliable, this mechanism ensured stable supply to Mumbai. However, with increasing demand, the scenario changed and Mumbai started facing challenges, especially during grid disturbances. In November 2010, peak demand in Mumbai was 3,130 MW, while internal generation was only 2,277 MW, creating a gap of 853 MW.[43] This gap had to be filled by importing power via the state's transmission network, highlighting the importance of a reliable, strong transmission network in the city.

The final report on Partial Grid Disturbance in Mumbai system (June 2011) submitted to MERC highlighted the urgent need for expediting specific transmission projects, including critical 400 kV and 220 kV lines and substations, to address reliability concerns, especially as local generation expansion was impractical.[44] This called for building specific projects for strengthening the city grid. However, due to limited space and increasing ROW issues, the project costs have been escalating.

Maharashtra’s composite tariff mechanism ensures that the cost of any transmission upgrades is shared by all users in the state, even though they mainly benefit some users. This leads to some level of socialization of transmission costs. Such socialization was challenged by MSEDCL in Case No. 327 of 2019. MSEDCL highlighted that various transmission licensees are developing transmission networks for Mumbai area to resolve the issue of

41. UPERC MYT Transmission Regulations, 2025. https://www.uperc.org/Notified_User.aspx
42. https://www.livemint.com/industry/energy/mumbai-s-power-islanding-system-needs-an-upgrade-11603084760885.html
43. Report on Partial Grid Disturbance in Mumbai System. https://merc.gov.in/wp-content/uploads/2022/07/FinalReportSubmitted-1.pdf
44. ibid. https://merc.gov.in/wp-content/uploads/2022/07/FinalReportSubmitted-1.pdf

transmission constraints. Since this would allow Mumbai utilities to procure cheaper power, the cost of such networks should be borne by Mumbai utilities alone.[45] The Commission acknowledged the importance of a fair transmission pricing framework that considers the actual beneficiaries and their usage of the network. However, later, in Case No. 230 of 2022, the Commission observed that the transmission charges in Maharashtra are shared according to the Transmission Pricing Framework stipulated under MYT Regulations, 2019, and costs would continue to be socialized across all transmission system users in the state.[46] The Commission has retained the same framework in its recent MYT Regulations 2024.

4.2. Long-term transmission charges

4.2.1. Analysis

We analysed the transmission tariff orders and regulations for 16 states namely, Assam, Gujarat, Karnataka, Madhya Pradesh, Telangana, Bihar, Tamil Nadu, Haryana, Uttar Pradesh, Punjab, Rajasthan, Uttarakhand, Andhra Pradesh, Maharashtra, Odisha, and West Bengal. The objective was to examine how long-term transmission charges are calculated, especially the parameters used as denominators for defining transmission capacity. The analysis shows considerable variation across states, as summarized in Table 18.

Table 18: Transmission capacity considered by various states

State	Transmission Capacity as per Tariff Regulations	Transmission Capacity as per Tariff Order
Assam	Not Mentioned	Max. Contracted Capacity
Gujarat, Karnataka, Telangana, Bihar	Contracted Capacity	Contracted Capacity
Madhya Pradesh	Allotted Transmission Capacity	Contracted Capacity
Tamil Nadu	Transmission Capacity allocated	Source-wise Contracted Capacity*
Haryana	Average of CPD and NCPD or Contracted Capacity	Contracted Capacity
Uttar Pradesh	Contracted Capacity	Energy transmitted
Punjab	Not Mentioned	Transmission Capacity
Rajasthan	Contracted Capacity	Peak Demand
Uttarakhand	Not Mentioned	Peak Demand
Andhra Pradesh	Peak Demand	Peak Demand
Maharashtra	Average of Coincident Peak Demand and Non-Coincident Peak Demand	Average of Coincident Peak Demand and Non-Coincident Peak Demand

45. Case No. 327 of 2019: Case of Maharashtra State Electricity Transmission Company Limited for Determination of Multi-Year Tariff for Intra-Sate Transmission System for the 4th MYT Control Period from FY 2020-21 to FY 2024-25.

46. Case No. 230 of 2022: Case of Adani Electricity Mumbai Limited – Transmission (AEML-T) for Truing up of Aggregate Revenue Requirement (ARR) for FY2019-20, FY 2020-21 and FY 2021-22, Provisional Truing-up of ARR for FY2022-23 and approval of Revised ARR for FY 2023-24 and FY 2024-25. https://merc.gov.in/wp-content/uploads/2023/03/Order-230-of-2022.pdf

State	Transmission Capacity as per Tariff Regulations	Transmission Capacity as per Tariff Order
Odisha	Energy handled by the system	Average demand
West Bengal	Allotted Transmission Capacity	Contracted capacity or Average of daily peak demand

Source: Compiled by PEG from intra-state tariff regulations and tariff orders.

Note: *50% of contracted Wind (non-REC) + 60% of contracted Biomass (non-REC) + 70% of contracted Co-generation (non-REC) + 50% of contracted Solar (Non-REC) + 100% of Other Sources.

To assess the impact of differing denominators (Table 18) on charges, we applied each state's formula (as per the methodology outlined in their respective tariff orders and tariff regulations) on a common set of assumptions (Table 19). The resulting long-term charges are shown in Table 20.

Table 19: Uniform Assumptions considered for calculation of transmission charges across states

Parameter	Assumed Value	Assumptions
Net ARR (₹ Crores)	5,600	
Transmission Capacity (MW)	37,201	
Energy transmitted (MUs)	1,47,600	
Contracted Capacity (MW)	37,201	
Average of CPD & NCPD (MW)	31,621	85% of Contracted Capacity
Average Demand (MW)	29,761	80% of Contracted Capacity
Peak demand (MW)	33,481	90% of Contracted Capacity
Maximum Contracted (MW)	40,921	110% of Contracted Capacity

Table 20: Variation in Long-term Transmission Charges across states

State	Transmission Capacity (as per formular used in Tariff order)	LTOA (₹/MW/Day)	% Variation w.r.t Base case
Assam #	Max. Contracted Capacity	3,749	
Gujarat, Karnataka, Madhya Pradesh, Telangana, Bihar, Tamil Nadu*, Haryana & Uttar Pradesh	Contracted Capacity	4,124	10%
Punjab	Transmission Capacity	4,124	10%
Rajasthan, Uttarakhand & Andhra Pradesh	Peak demand	4,582	22%
Maharashtra	Avg. of CPD & NCPD	4,852	30%
Odisha & West Bengal	Average Demand	5,155	38%

Source: Calculated and Compiled by PEG

Notes: 1) As per formulae given in tariff order, using common assumptions given in Table 19.

2) *50% of contracted Wind (Non-REC) + 60% of contracted Biomass (Non-REC) + 70% of contracted Co-generation (Non-REC) + 50% of contracted Solar (Non-REC) + 100% of Other Sources.

3) # Assam considers the maximum contracted capacity as the denominator for transmission capacity, resulting in the lowest LTOA charges. Therefore, it is treated as the baseline for this analysis.

4.2.2. Observations

Our analysis shows that different definitions of transmission capacity across states (Table 18) result in 10–38% variation in long-term transmission charges. This highlights the need for standardization in methodologies for determining these charges.

A notable case is Uttar Pradesh. As per MYT regulation of 2019,[47] the long-term charges were to be determined based on allotted transmission capacities to all long-term transmission customers of state transmission system. Short-term transmission charges were to be determined based on average capacity (MW), which was sum of generating capacities connected to transmission system and contracted capacities of other transactions handled by the system of transmission licensees. However, the regulations also provided for both long-term and short-term charges to be computed in ₹/kWh using energy transmitted (in kWh) as the denominator. This continues to remain the practice in the state, given that the exact contracted capacity of transmission users is not known. This has led to:

- Charges being recovered on ₹/kWh basis and identical charges for all categories.
- A departure from the well-established principle that:
  - LT charges should be based on capacity (₹/MW/month)
  - ST charges should be higher than LT charges.[48]

However, Regulation 29 of UPERC's MYT, 2025 has adopted a composite (pooled) transmission charge mechanism.

4.3. Short-term transmission charges

4.3.1. Analysis

States use varying parameters (as denominators) to calculate short-term transmission charges as well, as shown in Table 21. While many use energy transmitted, some use average demand or contracted capacity. In a few states, no explicit formula is noted in the regulations.

47. UPERC MYT Regulations, 2019. https://www.uperc.org/App_File/NotifiedMultiYearTariffforDistributionAndTransmissionRegulations2019-pdf1121201942418PM.pdf

48. UPPTCL: True-up for FY 2022-23, APR for FY 2023-24, ARR and Tariff for FY 2024-25. https://www.uperc.org/App_File/TariffOrderPetition2044of2023(UPPTCL)-PDF1010202461542PM.pdf

Table 21: Denominator used for calculation of short-term transmission charges by various states

State		Denominator a/c to formula in Tariff Order	Denominator a/c to formula in Regulations
Maharashtra, Haryana, Gujarat, Rajasthan, Odisha, Madhya Pradesh*		Energy Transmitted	Energy Transmitted
Uttar Pradesh		Energy Transmitted	Avg. demand×365×24
Bihar		Not Mentioned	Energy Transmitted
Punjab, Assam		Energy Transmitted	Not Mentioned
Tamil Nadu		Contracted Capacity×365×24	Not Mentioned
Karnataka	Up to FY 2024-25	Contracted Capacity×365×24	Contracted Capacity×365×24
	For FY 2025-26	Energy Transmitted	Energy Transmitted
West Bengal		Avg. demand365×24	Not Mentioned
Telangana		Contracted Capacity×365×24	Contracted Capacity×365×24

Source: Calculated and Compiled by PEG from tariff regulations

Note: *Only in the case of MP, the formula is given in the open access regulations.

Using each state's approach (as per the methodology outlined in their respective tariff orders and tariff regulations) and the assumptions in Table 19, we calculated short-term charges as shown in Table 22 and Table 23.

Table 22: Varying Short-term Transmission Charges for different states as per formula in Tariff Order

State		Denominator as per formula in Tariff Order	STOA as per formula in Tariff Order (Paise/kWh)
Maharashtra, Haryana, Gujarat, Rajasthan & Odisha, Uttar Pradesh, Madhya Pradesh, Punjab & Assam		Energy Transmitted	37.94
Tamil Nadu, Telangana		Contracted Capacity×365×24	17.18
Karnataka#	Up to FY 2024-25	Contracted Capacity×365×24	4.29
	For FY 2025-26	Energy Transmitted	37.94
West Bengal		Avg. demand×365×24	21.48
Uttarakhand & Andhra Pradesh, Bihar		Not Mentioned	NA

Source: Calculated and Compiled by PEG from tariff orders

Note: As per formulae given in tariff order, using common assumptions given in Table 19
For the state of Karnataka, as per tariff order STOA charges were calculated as
0.25 × (ARR /Contracted Capacity × 365 × 24) for 12 to 24 hours up to FY 2024-25.

Table 23: Varying Short-term Transmission Charges for different states as per formula in Tariff Regs.

<table>
<tr><th colspan="2">State</th><th>Denominator as per formula in Tariff Regulations</th><th>STOA as per formula in Tariff Regulations (Paise/kWh)</th></tr>
<tr><td colspan="2">Maharashtra, Haryana, Gujarat, Rajasthan, Odisha, Bihar & Madhya Pradesh*</td><td>Energy Transmitted</td><td>37.94</td></tr>
<tr><td colspan="2">Uttar Pradesh, West Bengal*</td><td>Avg. demand × 365 × 24</td><td>21.48</td></tr>
<tr><td colspan="2">Telangana</td><td>Contracted Capacity×365×24</td><td>17.18</td></tr>
<tr><td rowspan="2">Karnataka#</td><td>Up to FY 2024-25</td><td>Contracted Capacity×365×24</td><td>4.29</td></tr>
<tr><td>For FY 2025-26</td><td>Energy Transmitted</td><td>37.94</td></tr>
<tr><td colspan="2">Uttarakhand & Andhra Pradesh, Punjab, Assam &Tamil Nadu</td><td>Not Mentioned</td><td>Not Mentioned</td></tr>
</table>

Source: Calculated and Compiled by PEG from tariff regulations

Note: As per formulae given in tariff regulations, using common assumptions given in Table 19
* As per formulae given in open access regulations, using common assumptions given in Table 19
#For the state of Karnataka, as per Tariff regulations 2006, STOA charges were calculated as 0.25 × (ARR / Contracted Capacity × 365 × 24) for 12 to 24 hours up to FY 2024-25.

4.3.2. Observations

Short-term charge methodologies vary significantly across states. Based on Tables 21 and 22, the charges range from 17 to 38 paise/kWh (a 117% variation, excluding Karnataka) due to the variation in the value of the denominator.

In certain states like Telangana and Tamil Nadu, the short-term transmission charges when computed as per the framework outlined in their respective tariff orders are found to be equivalent to long-term transmission charges, whereas in Karnataka, the short-term charges are notably lower than the long-term transmission charges until FY 2024-25.

Notably:

- Many states offer waivers/concessions on InSTS charges for RE and captive transactions, though this trend is shifting.
- In UP and Karnataka, there are inconsistencies between formulas used in tariff orders and those in regulations.

Additionally for the states of Karnataka and Uttarakhand, STOA charges up to FY 2024-25 were calculated as:

Table 24: Short-term charges for the state of Uttarakhand, as given in open access regulations

For duration up to 6 hours	Equal to half of the long-term transmission charges
For duration greater than 6 hours	Equal to long-term transmission charges

Table 25: Short-term charges for the state of Karnataka

Short-term Rate (ST Rate) = 0.25 × [Net ARR /Total Contracted Capacity]/365	
Up to 6 hours in a day in one block	0.25 × ST Rate
More than 6 hours and up to 12 hours in a day in one block	0.50 × ST Rate
More than 12 hours and up to 24 hours in a day in one block	Equal to ST Rate

However, beginning with the tariff order for FY 2025-26, Karnataka has revised and aligned its methodology in accordance with the provisions laid out in the tariff regulations, 2024. Under the updated framework, the STOA charges are now calculated as the Net Aggregate Revenue Requirement (ARR) divided by the total energy transmitted over the system.

Finally, we observe that few SERCs (such as UPERC[49] and CSERC (draft)[50]) do not account for STOA income when calculating the Net ARR, which can result in double recovery of that portion of the ARR. However, the volume of short-term transactions is currently low, and therefore, the financial impact is likely minimal.

49. UPERC MYT Regulations, 2019. https://www.uperc.org/App_File/NotifiedMultiYearTarifffforDistributionAndTransmissionRegulations2019-pdf1121201942418PM.pdf

50. For example, the CSERC draft MYT regulation 2024 does not provide any information regarding income from STOA.

5. Suggestions on way forward

Driven by rising electricity demand and rapid renewable energy (RE) capacity growth, the Indian transmission system is projected to expand significantly in the coming years, with an estimated investment of approximately ₹9 lakh crore during 2022–2032 (see Table 1). This expansion underscores the need for improved transmission planning, cost-efficient project execution, and fair, forward-looking pricing mechanisms at both the ISTS and InSTS levels. Effective planning will require enhanced coordination across entities, improved data-sharing, and capacity-building of system planners. Cost efficiency can be improved through greater adoption of TBCB. Meanwhile, the development of a fair and transparent pricing framework must ensure that costs are recovered while sending the right economic signals.

Achieving a more effective pricing framework will require the development of improved cost allocation mechanisms and some level of standardization of methodologies across states. Ideally, *a well-designed transmission pricing framework should*

- *Provide economic signals for efficient use of transmission resources;*
- *Provide economic signals for investment in transmission;*
- *Provide economic signals for location of new generation and loads;*
- *Promote efficient day to day operation of the bulk power market including power trading;*
- *Compensate the owner of the transmission system by meeting its revenue requirement including returns; and*
- *Be simple and practical.*[51]

Tariff design must strike a balance between core principles such as cost recovery, efficiency, non-discrimination, transparency, stability, and predictability. However, in practice, not all these principles can be fully realized at once. Regulators must therefore strike a balance, often making trade-offs between these principles based on policy priorities and within legal mandates.[52]

The following suggestions for transmission pricing in the country are based on the analysis and observations across ISTS and InSTS pricing frameworks in previous chapters.

5.1. Enhance Regulatory Oversight of Transmission Planning

For ISTS planning, CERC recognised that, *"there is a need to have a transparent, coordinated consultative process for planning for the development of inter-State transmission system and associated intra-State transmission systems in an optimal manner."* To operationalise this aspect, it brought in the (Planning, Coordination and Development of Economic and Efficient Inter-State Transmission System by CTU and other related matters) Regulations, 2018 whose primary aim is to *"create a facilitative regulatory environment to enable CTU to plan an efficient, reliable*

51. ABPS Infrastructure Advisory Private Limited, Draft Approach Paper for Multi Year Tariff Regulations for FY 2010-11 to FY 2014-15 Submitted to Maharashtra Electricity Regulatory Commission. https://merc.gov.in/wp-content/uploads/2022/07/MYT_Approach_paper_25.09.2009.pdf

52. ACER Practice Report on Transmission Tariff Methodologies in Europe. https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Practice%20report%20on%20transmission%20tariff%20methodologies%20in%20Europe.pdf

and economical inter-State Transmission System and associated intra-State Systems through a transparent process of extensive, informed and inclusive consultation with stakeholders and get it developed in terms of the Electricity Act and Policies formulated under the Act."[53]

This made the ISTS planning process by the CTU more participative and transparent (through publication of base case files, cost benefit analysis of transmission, stakeholder consultations etc.) Presently, there is no equivalent regulatory mandate for STUs. A lacuna in the EA 2003 is the absence of a formal approval or vetting mechanism for the STU's transmission system plan. While the STU has statutory responsibility for planning, SERCs neither have the legal mandate nor the technical capacity to review or challenge these plans comprehensively.

To address this:

- SERCs may consider developing regulations under section 86(1)(c) of EA 2003, like CERC's 2018 transmission planning regulations, to bring transparency and process discipline into STU-led planning. This should also include mandatory publication of planning base case data, annual transmission plans, and consultation with open access users and RE developers. FoR can develop a model regulation for SERCs to ensure alignment across States.

- As part of such processes, SERCs should institutionalize structured oversight mechanisms, such as periodic reviews via the Grid Coordination Committee (GCC) or Monitoring and Coordination Committee (MCC). These forums can serve as platforms for transparency and accountability, ensuring that the STU explores all alternative and cost-effective planning approaches before finalizing its transmission plan. While this will not replace the STU's statutory role, it can help promote planning discipline, stakeholder scrutiny, and alignment with evolving demand, RE integration, and open access requirements.

Further reforms to supplement the above process include:

- To improve power system operation and planning and in line with Sections 31(2) and 39 of EA 2003, states should restructure STUs into functionally distinct entities for SLDC, STU, and Transmission Asset Owner/Operator, mirroring the central-level structure (i.e., Grid-India, CTU, and Powergrid). This will help increase autonomy and accountability.

- Following the MoP's 2021 advisory, states should begin phased transfer of 33 kV systems from DISCOMs to STUs to improve planning, reduce losses, and enhance reliability.[54]

5.2. Introduce Structured Multi-Stakeholder Consultations in Transmission Planning

Given the highly technical nature of the transmission sector, India's ISTS planning process is currently conducted primarily through internal committee deliberations among sector institutions—based on CEA-CTU studies. India's transmission-planning architecture has evolved rapidly over the past decade with the MoP setting up the National Committee on Transmission (NCT) in 2018 which was re-constituted in November 2019 and again in October 2021 with an expanded mandate to:

- Evaluate National Grid performance on a quarterly basis.

- Scrutinise all CTU expansion proposals, including the rolling five-year Annual Plan.

53. https://www.cercind.gov.in/2018/regulation/Transmission.pdf

54. https://www.pib.gov.in/PressReleasePage.aspx?PRID=1785488

- Propose expansion of ISTS after considering recommendations of CTU and views of Regional Power Committees (RPCs) and formulate packages for proposed transmission schemes, estimate their costs and decide the implementation route (TBCB or RTM).

In parallel, the erstwhile Empowered Committee on Transmission (ECT) was dissolved (2019) and the five Regional Power Committee (Transmission Planning) [RPCTP] forums were wound up in October 2021. These structural changes mark real progress, yet stakeholder participation remains narrow, largely limited to central agencies, state utilities and select CPSUs despite the public availability of NCT meeting minutes. State planning led by STUs is typically even less transparent. As a result, neither end-users who ultimately bear the tariff (Discoms, OA consumers) nor resource (generation, transmission, storage) developers, SERCs, research groups or technology providers can test the assumptions, propose lower-cost non-wire alternatives, or flag social-and-environmental risks early in the cycle. Given the scale of investment at stake and the growing diversity of market actors, formal, transparent and iterative consultations must become routine at both national and state levels.

Recommended design features

- Early, open publication of draft plans: CEA, CTU (ISTS) and STUs (InSTS) should release draft expansion proposals, base-case load-generation scenarios and cost assumptions at least 60 days before approval deadlines. While the CEA publishes the draft National Electricity Plan (Transmission) with a two month window for stakeholder comments, presently the CTU publishes draft Rolling Plans every six months, although the stakeholder comments window is quite short at only 2 weeks.[55] Further, while the CEA's Manual on Transmission Planning Criteria notes the need for stakeholder consultations (as per Section 7.2.2 & Section 7.4 in the new chapter 7 added in early 2025), these processes need to be significantly improved, especially in States.
- Accessible data & models: Post the base files (e.g.; PSSE or equivalent), demand-supply scenarios and cost build-ups in machine-readable formats to enable independent review.
- Two-stage engagement
    - Written comments: a window for all interested parties, state regulators, consumer groups, RE/IPPs, DISCOMs, financiers etc to file evidence-backed submissions. Creating this "comment window" may surface distributed-generation, demand-response, advanced conductors or dynamic-rating solutions that may defer expensive lines, deliver least-regret outcomes, and bolster investor and consumer confidence in the cost trajectory of India's grid.
    - Hybrid workshops: one technical round-table and one open hearing (physical and virtual) where planners respond to queries and present how feedback was addressed.
- Reasoned decision report: Final approvals (by NCT/STU boards or MoP where required) should be accompanied by a short report summarising stakeholder inputs, the rationale for accepting or rejecting suggestions, and the cost-impact of material changes.
- Replicate at the state level: Forum of Regulators (FoR) can issue model guidelines so that SERCs embed these consultation steps, scaled to state circumstances into their transmission-planning regulations.

55. CTU ISTS Network Expansion Schemes to be included in Rolling Plan Reports. https://ctuil.in/annual-rolling-plan/stakeholders

- Continuous improvement loop: Publish a biennial "consultation audit" measuring participation breadth, issue-resolution timelines and the accuracy of demand-supply forecasts, feeding lessons into the next planning cycle.

By institutionalising such structured, inclusive consultations, India can match the technical rigour of its planning processes with practices that build legitimacy, improve investment signals and ultimately lower the delivered cost of power.

5.3. Rationalise And Standardize InSTS Pricing Methodologies

Chapter 4 highlights wide variation in how states calculate long-term and short-term transmission charges. Disparities in formulas (between regulations and orders), parameters used (contracted or average capacity vs. energy), and treatment of demand lead to ~38% variation in long-term charges and ~127% variation in short-term charges across states. This divergence can lead to a lack of clarity and uniformity in the application of transmission tariffs, potentially creating challenges in ensuring fair and transparent cost recovery.

The transmission network is built for managing peak demand and hence long-term charges should be based on peak demand or contracted capacity, not on energy transmitted or average demand. Basing transmission charges on annual energy or average demand understates the cost responsibility of users who drive system peaks, because network capacity (and therefore the bulk of investment and fixed costs) is sized to meet coincident peak flows, not average utilisation. Energy linked long-term pricing thus shifts costs away from peakheavy consumers onto those with flatter load profiles, distorting economic signals for both network usage and future expansion.

Recommendations:

- States should harmonize tariff methodologies linking pricing to peak demand and further ensuring consistency between regulations and tariff orders. The FoR model regulation on open access also recommends pricing based on peak demand.[56]
- FoR should coordinate a model regulation for InSTS tariff design to ensure alignment across states.

5.4. Transition from Postage Stamp to Usage-Based Pricing in States

Despite Tariff Policy and National Electricity Policy calling for consistent intra- and inter-state pricing, most states still rely on the outdated postage stamp method, which does not reflect voltage, direction, distance, or actual usage. It has been more than 14 years since such a framework (PoC) was implemented at the ISTS level beginning in 2011. The Tariff Policy had suggested that states should also adopt a pricing mechanism similar to ISTS within two years.

Further, some states with multiple transmission licensees, such as Maharashtra, determine transmission charges using a composite tariff or pooling mechanism which introduces a challenge of socialisation of some costs (Box 6). This skews the cost distribution, raising concerns about fairness and efficiency.

To avoid this, the following are recommended:

States should transition within 1–2 years to a PoC-like framework based on load flow studies wherein pricing is linked to system utilisation. This will also help in bringing load flow analysis

56. FoR Report on Developing model regulations on methodology for calculation of open access charges and banking charges for green energy open access consumers.
https://forumofregulators.gov.in/Data/study/Final%20Report%20of%20FOR-GEOA.pdf

in public domain and would also help critically examine transmission network planning and development practices at state level. As in ISTS, transmission cost categories (e.g., National, Regional, Transformer, AC-usage) may be adopted at the state level with usage-based recovery for appropriate elements. While common elements will be shared amongst all users, user-specific elements are charged to the benefiting entity.

The FoR, in collaboration with STUs and other stakeholders, should develop a model intra-state PoC methodology aligned with national pricing design.

This transition will require state-level institutional capacity building — particularly for SLDCs and SERCs — in areas of data management, load flow analysis, tariff modelling, etc. Cross-agency learning between CERC, Grid-India, CTU, and their state counterparts through technical working groups on transmission pricing would be necessary.

5.5. Ensure Short-Term Charges are higher than Long-Term Charges

Historically, ST access was possible only with residual spare capacity in the system. Revenue from ST transactions cross-subsidised LT access by reducing overall charges for LT access. Further, such access had lower firmness, lower scheduling priority and higher curtailment risk. Given these risks and the fact that ST access used only the residual margins in transmission capacity, charges for ST access were not higher than LT access. While this continues to be the case for ST access to InSTS in states, it is becoming less relevant as ISTS has moved towards GNA-based firm access even for ST transactions.

Further, the scale of Open Access has significantly increased in the country over the last decade and many consumers (esp. C&I) are looking at OA as primary source of supply.

Short-term charges must logically exceed (to some extent) long-term charges, to reflect the premium for flexibility and discourage gaming by shifting from LT to repeated ST access. While ISTS adopted this change in 2023 (10% higher ST charges) (section 3.4), states do not follow this. This has a bearing on transmission planning and cost distribution amongst its users. Ideally, short-term charges should be derived from LT charges, adjusted by a multiplicative factor $x > 1$ (to be decided by the respective SERC), as per the following formula:

$$\textbf{Short – term charges (₹/MW/Block)} = x \times \frac{\textbf{Long – term Charges in ₹/MW/Day}}{\textbf{Number of blocks in a day (96)}}$$

States should adopt this approach and align with the ISTS methodology for coherence. SERCs should mandate SLDCs/STUs to publish monthly ST usage patterns, helping SERCs decide the x-factor with greater clarity.

Alternatively, States could also follow the example of MERC which has instituted a multiplier for repeated ST transactions as noted below.

14.1 (v) Transmission Charges, Second proviso: "Provided that the applicable transmission charges in case of such repeated STOA transactions of Open Access Consumer(s) shall be increased by a multiplication factor of 1.25, 1.5 and 2.0 respectively for every 2nd, 3rd and 4th STOA transaction during financial year beyond which the transmission charges for STOA shall be payable at two times of the approved transmission charges for STOA."[57]

57. https://merc.gov.in/wp-content/uploads/2022/07/DOA-Regulations-2019First-Amendment.pdf

5.6. Relook ISTS pricing methodology

While the PoC framework has evolved over time and many significant improvements have been done during 2011–2025, some aspects (noted below) should be critically examined going ahead.

- The usage-linked component has declined sharply over time (~25% in 2025), while non-usage components (AC-balance, ~ 45% in 2025) have grown (Table 15).
- Presently, AC usage based charges are determined based on the monthly ISTS peak block (where sum of net ISTS drawls by all states is maximum) and each state's contribution to it. To make this methodology more representative of the state's usage pattern and contribution to ISTS peak in different times, weekly calculation of usage patterns is a possibility that can be explored by CERC / Grid-India while determining monthly AC usage based charges. In time, even more granular calculation of usage patterns may be considered.
- While the change in the RE ISTS waiver methodology (from capacity to generation) has reduced the absolute level of exemption, the scale of RE projects connected to the ISTS is set to sharply increase. As of April, 2025 only 37 GW[58] of RE capacity are eligible for the RE waiver but given the ISTS pipeline of ~153 GW of RE, the share of capacity connected to ISTS eligible for the waiver will rise sharply. While the ISTS waiver framework for RE and ESS has helped accelerate capacity addition, it can soon become increasingly complex to implement fairly and transparently as exemptions are continued or phased out and absorbed across all consumers. CERC and Grid-India should periodically assess the cumulative financial impact of ISTS RE and ESS waivers and ensure transparent allocation of exempted costs across beneficiaries.
- Finally, the draft 4th amendment to the Connectivity and GNA regulations of the ISTS proposes a differentiation between ISTS access during solar and non-solar hours.[59] This will likely reflect in changed load flows and the associated usage pattern of the consumer/s having access during solar and non-solar hours. This is very important since the largest share of the 153 GW RE pipeline belongs to solar projects, at 94 GW (61%).

Given these developments, a comprehensive re-evaluation of the ISTS pricing framework is prudent.

5.7. Accelerate InSTS Projects via Competitive Bidding (TBCB)

While most states have notified TBCB thresholds, adoption remains slow. As of March, 2025, 62 ISTS schemes have been commissioned[60] and 85 are under construction.[61] According to MoP,

58. CEA Renewable Project Monitoring Division, Daily Renewable Generation Report (All India). https://cea.nic.in/wp-content/uploads/daily_reports/1_May_2025.pdf
59. CERC Connectivity and GNA to the ISTS (Fourth Amendment) Regulations, 2025. https://cercind.gov.in/2025/draft_reg/DN3.pdf
60. CEA Monthly Report of Commissioned Transmission Projects awarded through Tariff Based Competitive Bidding (TBCB) Route March, 2025. https://cea.nic.in/wp-content/uploads/transmission/2025/03/Report_Commisioned_TBCB_March25.pdf
61. CEA Monthly progress Report of Under Construction Transmission Projects awarded through Tariff Based Competitive Bidding (TBCB) Route March, 2025. https://cea.nic.in/wp-content/uploads/transmission/2025/03/Report_UC_TBCB_March25.pdf

compared to the cost- plus projects (RTM), a 30-40% tariff reduction[62] is possible through the TBCB route. States and SERCs should prioritize TBCB for new InSTS projects, reducing the burden on regulators to determine prudent costs annually for RTM projects.

5.8. Move Towards an Integrated ISTS-InSTS Pricing Framework in the long run

The divergence in pricing methodologies—where ISTS and InSTS charges are determined separately by CERC and respective SERCs—has led to misalignment between national and state-level transmission pricing. This fragmentation results in two major inefficiencies:

- Lack of coordinated transmission planning, as differing pricing principles make it difficult to harmonize network development strategies across jurisdictions.
- Pancaking of charges and losses takes place when the transaction involves the use of both- the ISTS and InSTS networks.[63]

These issues ultimately impede the development of a reliable, efficient, and integrated national electricity grid. To overcome this, the first step would be for SERCs to align InSTS pricing frameworks with the ISTS as outlined in Sections 5.3 and 5.4. Here the focus should be on harmonizing tariff principles using a model framework developed by the FoR. Such a framework will be conscious of the federal structure, ensure transparency, and allow for state-specific flexibility while achieving greater national efficiency.

Once states institutionalise a pricing framework sensitive to distance, direction and flow, the next step would be to explore a uniform, single pricing framework for transmission access—applicable across the ISTS and InSTS networks (One Nation One Transmission Grid (OTG)). This approach offers a promising long-term solution and such a framework was recommended by the *Transmission Expert Group in the report Transmission Reform Agenda and Action Plan for India* (Idam Infra and Prayas (Energy Group), 2021).[64] To operationalize such a single integrated pricing model as illustrated in Figure 3, the following steps are suggested:

- Harmonization of Regulatory Principles: For OTG implementation, there must be uniform regulatory treatment for ARR determination across all transmission licensees. This will ensure consistency in pricing outcomes and reduce distortions. The FoR should develop a model framework to harmonize these principles across states.
- Approval of ARRs: The existing jurisdictional roles will continue, where CERC and SERCs approve the ARRs or adopt tariffs discovered via TBCB for the transmission licensees under their purview.

62. https://powerline.net.in/2021/05/26/private-play/#:~:text=MoP%20recommends%20adoption%20of%20TBCB%20for%20intra%2Dstate%20transmission%20projects.&text=In%20light%20of%20these%20gains%20and%20in,the%20development%20of%20the%20intra%2Dstate%20transmission%20system

63. One possibility to avoid pancaking (both charges and losses) in the existing system can be by imposing ISTS charges and losses only on the actual flows out of state rather than on each transaction as is the case presently. For instance, when InSTS connected generators are selling on Exchanges, network charges for both InSTS and ISTS are levied, even in the cases when the actual flows/exports from the state are zero/negative (all the power is absorbed within the state). In other words, the charges and losses should be imposed only on the actual exports from the state.

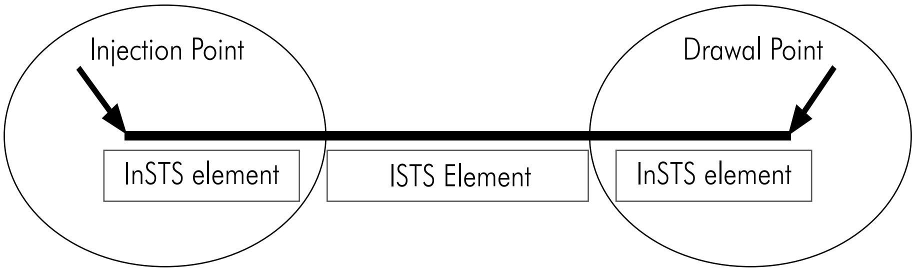
64. Transmission Reform Agenda and Action Plan for India By - Idam Infra and Prayas (Energy Group) (2021). https://indiatransmission.org/additional-resources/other-reports

- Unified Pricing: Ideally, for all transmission systems above a specified voltage threshold (e.g., 132 kV), Grid-India—may determine access and usage charges, irrespective of whether the asset is classified as ISTS or InSTS. However, before mandating such a unified pricing mechanism, InSTS assets critical for ISTS flows can be voluntarily brought in the unified pricing pool by respective States. Grid-India may use the full network (ISTS and InSTS up to 132 kV) for calculating the usage-based charges. Already ~ 40 InSTS lines which are critical for ISTS flows have their tariff fully determined by CERC under the PoC mechanism in such a unified manner.

  This can be further streamlined by having states designate 220 kV / 132 kV lines that significantly carry ISTS flows identified through Power Transfer Distribution Factor (PTDF)[65] studies by Grid India as ISTS, subject to validation by the respective RPCs. The ARR of such lines may be pooled with ISTS and the line's ARR is split based on a "sharedbenefit ratio" (e.g.; 40 % pooled as ISTS, 60 % stays in the state ARR) in proportion to its average ISTS PTDF contribution. GridIndia could publish quarterly PTDF dashboards to enable states to analyse the benefit of volunteering more assets. The proposed model would help in reducing the burden of InSTS charges on states and nudge them towards an integrated pricing model, if they perceive any advantages in the long-term. This kind of voluntary and cooperative approach will help in aligning on principles while preserving the respective roles of CERC and SERCs and could be one path going forward. After a trial period (say 3-5 years), such a unified pricing framework may be made mandatory after evaluating systemwide cost shifts and benefits.

The move toward an integrated pricing framework will undoubtedly pose transitional and institutional challenges which may require legislative amendments or nudges towards voluntary adoption. However, its long-term benefits—including reduced pancaking, improved efficiency, and fairer cost allocation—are expected to significantly outweigh the costs.

Figure 3: Single pricing model for One Nation One Transmission Grid (OTG)



To support this transition, it is recommended that the FoR constitute a working group comprising experts from Grid-India, CEA, CTU, and STUs. This group should examine:

- Practical challenges in merging frameworks.
- Legal and regulatory enablers required.

65. PTDF (Power Transfer Distribution Factor) is a metric used in power systems to determine how a change in power injection or withdrawal at one location affects the flow on transmission lines across the network. PTDF quantifies the sensitivity of power flow on a particular transmission line due to a unit (1 MW) transfer of power from one node (point) in the grid to another. e.g. If a PTDF value for a line is 0.3 for a transfer from Bus A to Bus B, it means that 30% of the transferred power (i.e., 0.3 MW for 1 MW injection at A and withdrawal at B) will flow through that particular transmission line.

- Methodologies for allocation of costs and access charges.
- Timelines and roadmap for implementation.

Such a deliberative process will help build consensus and ensure that the proposed reforms are technically sound, legally feasible, and widely supported.

Tariff reform is a policy lever that shapes incentives, signals investment needs, and ensures the equitable use of public infrastructure. Getting it right is fundamental to India's energy transition, economic competitiveness, and consumer welfare.

Efficient and equitable transmission pricing is crucial for India's rapidly expanding electricity grid, especially as renewable energy increasingly shapes the electricity landscape. In this discussion paper, we provide a comprehensive review of how inter-state (ISTS) transmission pricing has evolved over the past two decades, transitioning from simple energy-based charges to sophisticated usage-based frameworks like the Point of Connection (PoC) and General Network Access (GNA).

We critically assess the existing intra-state (InSTS) pricing mechanisms across various Indian states, identifying significant issues such as pricing distortions, limited regulatory oversight, and inconsistent tariff methodologies. We advocate transitioning from uniform postage stamp tariffs to pricing models that better reflect actual usage and incurred costs.

Our analysis presents practical, evidence-based recommendations for reform. These include enhancing regulatory oversight in transmission planning to improve transparency and accountability, standardizing and rationalizing state-level pricing methodologies to ensure fairness and efficiency across jurisdictions and introducing structured multi-stakeholder consultations in planning processes to improve decision-making. Furthermore, we recommend gradually integrating ISTS and InSTS pricing frameworks to eliminate inefficiencies and support seamless open access. Ultimately, our goal is to establish a coherent, harmonized, and dynamic transmission pricing regime that incentivizes efficient investment and paves the way for a robust and integrated national transmission pricing structure.

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