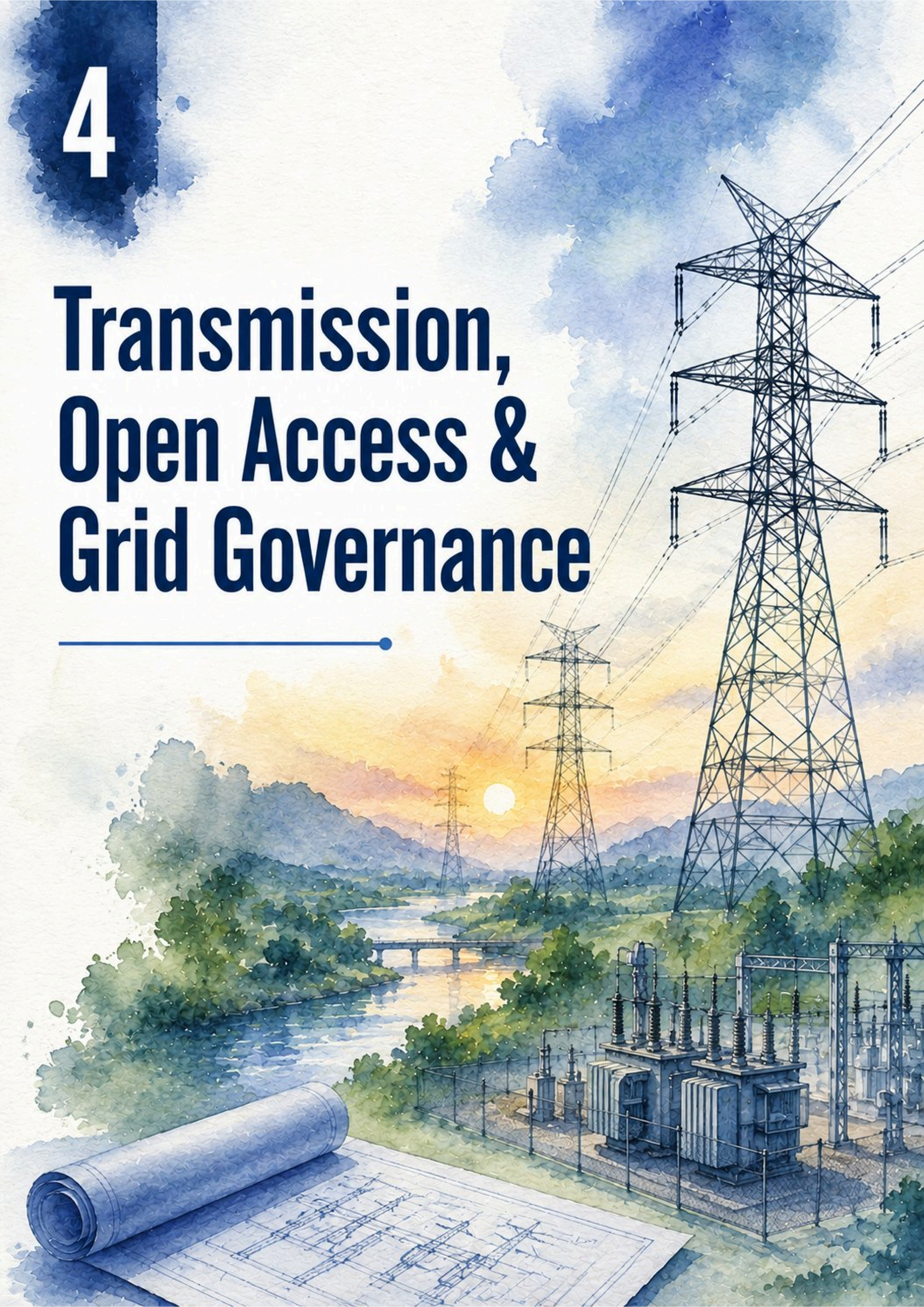
4

Transmission, Open Access & Grid Governance



Transmission, Open Access & Grid Governance

Booklet IV of VI

Bhatt & Joshi Associates

TABLE OF CONTENTS

CHAPTER ONE

Transmission System Architecture

ISTS Structure, CTU Role, Sections 38-41, and the Five Regional Grids

India's inter-state transmission system is the physical backbone of the national electricity market, enabling power to flow from generation-surplus to demand-deficit regions across the country. This chapter examines the legal and institutional architecture of the transmission system.

1.1 Constitutional and Statutory Framework for Transmission

The regulation of inter-state electricity transmission falls within Parliament's legislative domain as a consequence of the Supreme Court's consistent position that the transmission of electricity across state boundaries constitutes inter-state trade and commerce within the meaning of Article 302 of the Constitution, engaging the Central Government's authority over inter-state trade. The Electricity Act, 2003 vests CERC with jurisdiction over all matters relating to the inter-state transmission system (ISTS) under Section 79(1)(c), including the determination of tariffs for ISTS assets, the approval of investments in ISTS expansion, and the adjudication of disputes between ISTS users. CERC's jurisdiction over the ISTS is exclusive: no state government or SERC can exercise authority over the planning, development, operation, or commercial arrangements of ISTS assets, even if those assets pass through the state's territory.

The legal framework for transmission in India is structured around three key provisions of the Electricity Act, 2003. Section 38 designates the Central Transmission Utility (CTU) as the entity responsible for coordinating ISTS planning, development, and operation, and currently Powergrid Corporation of India Limited (PGCIL) serves as the CTU. Section 39 specifies the CTU's functions, including planning, developing, and operating the ISTS; providing non-discriminatory open access to the ISTS; and complying with CERC's directions. Section 40 specifies the duties of the CTU, including the maintenance of a nationwide network map and the reporting of transmission capacity utilisation to CERC. These provisions establish the legal basis for PGCIL's dominant role in India's inter-state transmission infrastructure.

1.2 Powergrid Corporation of India: History and Role

Powergrid Corporation of India Limited, incorporated in 1989 as a Central Public Sector Enterprise under the Companies Act, was established to take over the inter-state transmission assets of the National Thermal Power Corporation (NTPC), the National Hydroelectric Power Corporation (NHPC), and other central generating companies, and to develop these assets into a national transmission network. PGCIL has grown from a relatively modest initial asset base to become the owner and operator of over 1,65,000 circuit kilometres of transmission lines and over 250 ISTS substations, making it one of the largest transmission companies in the world by asset scale. PGCIL's unique national mandate, its experience with large transmission project development, and its role as the CTU under the EA 2003 make it the central institutional pillar of India's ISTS infrastructure.

PGCIL operates under a regulated asset base model, with CERC determining the annual transmission tariff for each ISTS element based on the cost-of-service methodology. The stability and predictability of CERC's regulatory framework has provided PGCIL with the revenue certainty needed to finance its capital-intensive expansion programme through a combination of internal accruals, commercial borrowings, and institutional finance from multilateral development banks (including the World Bank and the Asian Development Bank). PGCIL's strong regulatory regime and its Central Government ownership (which implies an implicit government guarantee on its debt) have enabled it to raise large volumes of debt capital at competitive rates, reducing its financing costs and the ISTS tariff payable by electricity consumers.

1.3 Regional Electricity Architecture: Five Regional Grids

India's electricity grid is organised into five regional grids: the Northern Regional Grid (comprising Delhi, Rajasthan, Uttar Pradesh, Uttarakhand, Punjab, Haryana, Himachal Pradesh, and J&K); the Western Regional Grid (comprising Maharashtra, Gujarat, Madhya Pradesh, Chhattisgarh, and Goa); the Southern Regional Grid (comprising Andhra Pradesh, Telangana, Karnataka, Tamil Nadu, and Kerala); the Eastern Regional Grid (comprising West Bengal, Bihar, Jharkhand, Odisha, and Sikkim); and the North-Eastern Regional Grid (comprising Assam, Arunachal Pradesh, Meghalaya, Manipur, Mizoram, Nagaland, and Tripura). The five regional grids are all interconnected through high-voltage inter-regional transmission links, forming the synchronous national grid that was completed with the incorporation of the Southern Grid in January 2014.

The physical and commercial architecture of the five regional grids creates a framework for the analysis of inter-state and inter-regional electricity flows. Within each region, the States are connected to each other and to the ISTS through their state transmission utilities' network, and power flows are managed by the Regional Load Despatch Centre (RLDC) with assistance from the State Load Despatch Centres (SLDCs). Power flows between regions pass through specific inter-regional transmission corridors (the high-voltage transmission lines that connect the ISTS substations of adjacent regional grids), whose capacity determines the volume of electricity that can be exchanged between regions at any given time. CERC and the CTU continuously monitor the utilisation of these inter-regional corridors and plan additional capacity to relieve congested corridors as demand grows and the renewable generation mix changes.

1.4 Private Transmission Licensees

The Electricity Act, 2003 enables private sector entities to develop and operate transmission elements in the ISTS under a transmission licence from CERC. The private transmission licensing framework was introduced to accelerate the pace of ISTS expansion by mobilising private sector capital and management expertise, complementing PGCIL's development programme. The competitive transmission development framework, under which PGCIL (or its subsidiary) and private bidders compete for the right to develop specified ISTS elements under a regulatory framework specifying the tariff ceiling for the element, was introduced through CERC's regulations and has produced several successful private transmission projects.

Private transmission licensees operate under the same CERC tariff regulatory framework as PGCIL: they receive CERC-determined annual transmission charges based on the approved capital cost and normative parameters of their transmission assets, and they provide non-discriminatory open access to ISTS users on the same terms as PGCIL. Major private transmission companies operating in the ISTS space include Adani Transmission, Sterlite Power, Torrent Power, and several others. Their participation in the ISTS has brought additional capital, project management expertise, and technology innovation to the transmission sector, though disputes about the regulatory treatment of their capital costs and the competitive transmission development process have generated significant regulatory litigation before CERC and APTEL.

1.5 National Electricity Plan and Transmission Investment

The National Electricity Plan (NEP) prepared by the Central Electricity Authority under Section 3(4) of the Electricity Act, 2003 provides the long-term roadmap for transmission infrastructure investment in India. The NEP's transmission chapter specifies the new ISTS elements (transmission lines and substations) required to support the projected growth in inter-state power flows arising from: the addition of new central generating capacity; the development of state-level renewable energy capacity that needs inter-state evacuation; and the increased flexibility requirements of the evolving electricity market. PGCIL prepares its own rolling transmission investment plan consistent with the NEP, which is approved by CERC as the basis for new ISTS investment commitments.

The planning methodology for transmission investment has evolved significantly with the growth of renewable energy, which has changed the pattern of power flows on the ISTS. The Green Energy Corridors identified in the NEP reflect the need to strengthen transmission capacity in the corridors connecting major renewable energy zones (Rajasthan, Gujarat for solar; Tamil Nadu, Andhra Pradesh for wind) with major load centres in other states. The challenge of transmission planning for renewable energy is that the timing and location of renewable energy development is determined by competitive market outcomes (competitive bidding results) rather than by centralised planning decisions, making it difficult to coordinate transmission infrastructure development with renewable capacity additions in real time. CERC and the CTU have developed adaptive transmission planning processes that attempt to anticipate likely renewable development patterns while maintaining flexibility to accommodate deviations from planned trajectories.

CHAPTER TWO

Open Access: Legal Framework and Implementation

LTA, GNA Regulations, Scheduling, and Non-Discriminatory Access

Open access — the right of generators and consumers to use the transmission and distribution network for electricity transactions without discrimination — is one of the cornerstones of competitive electricity market development under the Electricity Act, 2003. This chapter examines the legal framework and implementation of open access to the ISTS and distribution networks.

2.1 The Open Access Mandate: Sections 38-42

Sections 38 through 42 of the Electricity Act, 2003 collectively establish the open access mandate for India's electricity transmission and distribution networks. Section 38(2)(d) requires the CTU to provide non-discriminatory open access to the ISTS; Section 39(2)(c) imposes the same obligation on other transmission licensees; Section 40(c) specifies that it is a duty of every transmission licensee to provide open access; and Section 42(2) requires every distribution licensee to provide non-discriminatory open access to its distribution network to any person, on payment of the wheeling charges specified by the relevant Commission. These provisions, read together, create a comprehensive legal obligation of non-discriminatory open access throughout the electricity network — from the ISTS to the last-mile distribution network — that cannot be denied to any eligible consumer or generator except on specified technical grounds.

The open access framework has transformed India's electricity sector by enabling: large industrial and commercial consumers to procure electricity competitively from generators of their choice, bypassing the regulated supply of the distribution licensee; generators to sell electricity to the market rather than being entirely dependent on long-term bilateral PPAs; and the development of competitive electricity trading, including the power exchange segment of the market. The growth of open access transactions — from a small fraction of total electricity consumption in 2003 to a substantial share of large industrial and commercial electricity procurement today — reflects the progressive realisation of the competitive market vision of the EA 2003 through the open access framework.

2.2 GNA Regulations 2022: A Simplified Framework

The CERC (Connectivity and General Network Access to the Inter-State Transmission System) Regulations, 2022 replaced the earlier framework of Long-Term Access (LTA), Medium-Term Open Access (MTOA), and Short-Term Open Access (STOA) with a unified General Network Access (GNA) framework. The earlier framework had become increasingly complex and difficult to administer as the volume and variety of ISTS transactions grew, and the separation of LTA and MTOA from STOA created administrative bottlenecks and commercial rigidities that inhibited market development. The GNA framework simplifies the access architecture by: creating a single GNA entitlement that covers all categories of ISTS access (long-term, medium-term, and short-term) for entities that hold a GNA approval; enabling GNA holders to transact in any electricity market segment (bilateral contracts, power exchanges, ancillary services) without separate approvals for each transaction type; and streamlining the application and approval process for GNA.

Under the GNA framework, a generating company seeking ISTS connectivity submits a single GNA application to the CTU specifying its contracted generation capacity and the ISTS substation at which it seeks to connect. The CTU processes the application, verifies that the requested GNA can be accommodated within available transmission capacity, and issues a GNA approval specifying the connectivity point, the approved injection capacity, and any conditions on the GNA. The GNA approval is valid for the life of the generating asset and does not need to be renewed for changes in the generating company's commercial arrangements (new PPAs, power exchange participation, open access arrangements), providing much greater commercial flexibility than the earlier LTA framework which was tied to specific bilateral PPAs.

2.3 Short-Term Open Access: Day-Ahead and Intra-Day

Short-term open access (STOA) to the ISTS enables generators and consumers to schedule electricity transactions of up to 90 days' duration on the ISTS, using the residual capacity not committed to GNA holders for their long-term transactions. CERC's Short-Term Open Access Regulations specify the procedure for scheduling STOA transactions, the priority of different transaction types in the STOA scheduling queue, the charges applicable to STOA transactions (including the ISTS short-term open access charges), and the curtailment methodology when the volume of requested STOA transactions exceeds available ISTS capacity.

The DAM and RTM segments of the Power Exchanges are effectively integrated with the STOA framework: transactions concluded on the exchanges are automatically processed for ISTS scheduling through the CERC-approved settlement and scheduling process, without requiring separate STOA applications for each exchange transaction. This integration of the exchange market with the ISTS scheduling framework has significantly improved the efficiency of short-term electricity trading in India, reducing the administrative burden for market participants and enabling the rapid growth of exchange-based trading volumes.

2.4 Distribution Network Open Access: Section 42

Section 42(2) of the Electricity Act, 2003 requires distribution licensees to provide non-discriminatory open access to their distribution network for any person requesting it, subject to payment of wheeling charges and surcharges specified by the SERC. Open access to the distribution network enables: large industrial and commercial consumers connected at the distribution voltage level to procure electricity through the open access framework rather than solely from the distribution licensee's regulated supply; captive and group captive power plant owners to wheel their captive generation through the distribution network to their own consumption points; and renewable energy generators connected to the distribution network to sell their output to procurers through open access arrangements.

The distribution network open access framework involves three distinct charges: the wheeling charge (for the use of the distribution infrastructure, computed as described in Booklet II); the cross-subsidy surcharge (CSS) under Section 42(4), which recovers the cross-subsidy that the departing consumer category was providing to other categories; and the additional surcharge (AS) under Section 42(4), which recovers the fixed cost of conventional generation capacity stranded by the consumer's departure. The aggregate of these three charges determines the total network access cost for the open access consumer, and their quantum relative to the market price of electricity determines whether open access is economically attractive compared to regulated supply from the distribution licensee.

2.5 Non-Discrimination in Transmission Access

The legal obligation of non-discrimination in open access, derived from Sections 38–42 of the EA 2003 and elaborated through CERC's and the SERCs' open access regulations, prohibits the CTU, transmission licensees, and distribution licensees from: preferring or favouring any particular entity in the grant of open access or in the scheduling of open access transactions; imposing conditions on open access that are not specified in the applicable regulations; denying open access without establishing a specific technical or regulatory ground for denial; and taking actions that effectively impede open access even if they do not technically constitute a denial. APTEL has consistently enforced the non-discrimination obligation, setting aside open access refusals that were not supported by specific technical or regulatory grounds and directing transmission licensees and distribution utilities to process open access applications expeditiously and on non-discriminatory terms.

2.6 Green Energy Open Access: The 2022 Rules

The Electricity (Promoting Renewable Energy through Green Energy Open Access) Rules, 2022 represent the most significant open access reform since the Electricity Act, 2003, reducing the minimum load threshold for open access from 1 MW (in most states' existing regulations) to 100 kW and mandating a 15-day processing timeline for green energy open access applications. The 2022 Rules override any inconsistent state-level open access regulations, using the Central Government's rule-making power under Section 176 of the Act to establish a nationally uniform minimum standard for green energy open access that supersedes the patchwork of state-level regulations that had previously created significant variation in open access access terms across states. The Rules are specifically targeted at reducing the barriers to renewable energy procurement by smaller commercial and industrial consumers who cannot meet the 1 MW threshold of many existing state regulations but whose aggregate demand for renewable electricity could be significant if accessible through the open access framework.

CHAPTER THREE

Grid Code and System Operation

IEGC, Scheduling and Despatch, Frequency Regulation, and POSOCO

The Indian Electricity Grid Code (IEGC) is the technical and commercial rulebook governing the operation of India's synchronous national grid. This chapter examines the IEGC framework, the scheduling and despatch process, frequency regulation, and the role of the load despatch hierarchy.

3.1 Indian Electricity Grid Code: Legal Status and Content

The Indian Electricity Grid Code (IEGC), issued by CERC under Section 79(1)(h) of the Electricity Act, 2003, is a binding regulatory instrument specifying the technical and commercial requirements for entities connected to and operating on the inter-state transmission system. The IEGC has the legal status of a CERC regulation, enforceable through CERC's regulatory powers and ultimately through the Act's penalty provisions. Entities connected to the ISTS — including generating companies, distribution utilities, large consumers, and the load despatch centres themselves — are required to comply with the IEGC as a condition of their connectivity to and participation in the ISTS.

The IEGC covers the following principal subjects: the technical standards for connection to the ISTS, including the voltage and frequency requirements, the protection relay settings, and the communication interface specifications; the scheduling and despatch process, including the procedures for submitting day-ahead generation schedules, revising schedules, and issuing despatch instructions; the frequency and voltage regulation requirements, including the governor control requirements for synchronous generators and the reactive power capability requirements for all connected entities; the Deviation Settlement Mechanism (DSM), including the methodology for measuring and pricing deviations from approved schedules; the ancillary services framework, including the procedures for procuring and compensating frequency support and reserve services; and the outage planning and coordination process for scheduled maintenance outages of generating and transmission assets.

3.2 Scheduling and Despatch: The 15-Minute Block Framework

India's electricity scheduling and despatch framework operates on a 15-minute time block basis, with each 15-minute block corresponding to one Settlement Period for DSM and energy accounting purposes. In each 15-minute block, the net electricity flow from each generating station and the net demand of each distribution utility and large consumer is metered, compared to the approved schedule for that block, and the resulting deviation (positive or negative) is settled through the DSM mechanism at the applicable DSM charge for the block.

The scheduling process begins approximately 10 days before the delivery date with the submission of Unit Availability Declarations (UAD) by generating companies, followed by the day-ahead scheduling process on the day before delivery and multiple intra-day revision processes as actual conditions develop. The RLDC coordinates the scheduling across all entities in the regional grid, ensuring that the aggregate scheduled generation matches the aggregate scheduled consumption in each 15-minute block (including appropriate reserves) and that the resulting power flows on the transmission system are within the safe operating limits of all ISTS elements. The NLDC coordinates the scheduling across all five regional grids at the national level, managing inter-regional power flows and maintaining the overall frequency stability of the synchronous national grid.

3.3 Frequency Regulation and Governor Control

The maintenance of the grid frequency within the acceptable range specified in the IEGC (49.90–50.05 Hz under normal conditions, with wider emergency bands) is the primary measure of the real-time balance between generation and demand on the grid. When generation exceeds demand, the grid frequency rises; when demand exceeds generation, the frequency falls. Frequency deviations beyond the acceptable range can cause tripping of generating units (whose protection systems disconnect the unit if frequency deviates excessively), cascade failures of the transmission system, and ultimately widespread grid collapse if the imbalance is not corrected promptly.

The IEGC requires all synchronous generating units connected to the ISTS to operate with their governors in the free droop mode, enabling the generator's output to automatically respond to frequency deviations (the "primary response" or "governor response"). A generator operating in free governor mode increases its output when frequency falls below the set point and reduces output when frequency rises above the set point, providing an automatic and near-instantaneous corrective response to frequency deviations without requiring instructions from the load despatch centre. This distributed automatic response is the first line of defence against frequency instability, supplemented by the secondary response (Automatic Generation Control, or AGC) through which the RLDC automatically adjusts the generation setpoints of selected generating units to restore frequency to its nominal value after a disturbance.

3.4 POSOCO and the Load Despatch Hierarchy

The Power System Operation Corporation of India Limited (POSOCO), incorporated in 2009 as a wholly owned subsidiary of PGCIL and subsequently transferred to government ownership, serves as the National Load Despatch Centre (NLDC) under Section 26 of the Electricity Act, 2003 and manages the five Regional Load Despatch Centres (RLDCs). POSOCO's core function is the real-time operation of India's synchronous national grid, including: monitoring the grid frequency, voltage, and power flows on a continuous basis; issuing instructions to generators and load despatch centres to maintain grid stability; coordinating inter-regional power flows within safe operating limits; managing generation and transmission outages; and administering the DSM and energy accounting settlement processes.

The State Load Despatch Centres (SLDCs), designated under Section 31 of the Electricity Act, 2003, manage the real-time operation of each state's electricity system, including the intra-state generation, transmission, and distribution. The SLDCs coordinate with the RLDCs on the state's injection and withdrawal from the ISTS, and are responsible for maintaining the state's adherence to its approved ISTS schedule. The SLDCs also manage the scheduling of intra-state generation and the despatch of power from the state's generation portfolio to meet intra-state demand, coordinating with the state's distribution utilities to ensure adequate supply for all consumer categories.

3.5 Grid Disturbances and Emergency Protocols

Grid disturbances — unexpected events that cause large and rapid imbalances between generation and demand, threatening grid stability — are managed through a set of emergency protocols specified in the IEGC and the State Grid Codes. The severity of grid disturbances ranges from minor frequency deviations (managed through normal governor response and DSM) to major generation or transmission outages (requiring automatic or manual load shedding to restore the generation-demand balance) to full grid collapse (requiring a black start process to restore the grid from complete de-energisation). India's grid has experienced several major disturbances, including the catastrophic grid collapse of 30–31 July 2012 that affected 22 states and approximately 620 million people, prompting major reforms to the IEGC and the operational practices of the load despatch hierarchy.

The reforms following the 2012 grid collapse included: strengthening of governor control requirements for all generating units; enhanced monitoring and enforcement of overdrawal by state utilities; development of automatic load shedding schemes that protect the grid by automatically curtailing demand when frequency falls below critical thresholds; improvement of communication and coordination protocols between the NLDC, RLDCs, and SLDCs; and investment in real-time energy management systems at POSOCO and the RLDCs. These post-2012 reforms significantly improved the resilience of India's grid, and no comparable disturbance has occurred since, though the increasing variability of a high-renewable grid creates new operational challenges that require continued investment in grid management capabilities.

CHAPTER FOUR

Transmission Tariff and Cost Allocation

ISTS Sharing Methodology, Nodal Pricing Concepts, and Regulatory Practice

The allocation of transmission costs among users of the ISTS is one of the most commercially significant and technically complex aspects of electricity regulation in India. This chapter examines the methodology for ISTS cost sharing, the regulatory framework for transmission tariff determination, and the evolution towards more efficient pricing mechanisms.

4.1 Annual Transmission Cost: Computation and Components

The total ISTS Annual Transmission Cost (ATC) is the sum of the annual transmission charges for all individual ISTS elements, as determined by CERC through project-specific tariff orders. PGCIL (as the CTU) and private transmission licensees receive the ATC for their respective ISTS assets, with CERC ensuring that the total ATC is adequate to cover the prudently incurred costs of ISTS infrastructure development and operation while not allowing excessive returns on inefficient investment.

The tariff for each individual ISTS element is determined by CERC on the basis of the approved capital cost, the normalised debt-equity ratio (70:30), the applicable return on equity (15.5% per annum), the applicable interest rate on debt, the normative O&M expenses, and the depreciation schedule. The resulting annual revenue requirement for each element is the Annual Fixed Charge (AFC) payable by ISTS users regardless of the actual utilisation of the element. The transmission regulatory framework does not include a variable charge component (unlike the generation tariff which has both a fixed AFC and a variable ECR), reflecting the reality that the marginal cost of additional power flows on an existing transmission element (within its capacity limit) is essentially zero once the fixed infrastructure investment is made.

4.2 Sharing Methodology: Point of Connection and Postage Stamp

The CERC (Sharing of ISTS Charges and Losses) Regulations, 2020 specify the methodology for allocating the total ISTS ATC among the two primary user categories: generators (who inject power into the ISTS) and beneficiary states or distribution utilities (who withdraw power from the ISTS). The methodology uses different approaches for different categories of users, as described in Booklet II's detailed analysis. For renewable energy generators, the ISTS charge is currently waived for a specified period consistent with the policy objective of promoting renewable energy deployment. For conventional generators and distribution utilities, a modified postage stamp methodology allocates charges in proportion to contracted injection or withdrawal capacity.

The sharing methodology has been revised multiple times since the initial formulation of CERC's sharing regulations, reflecting the evolution of the ISTS user base and the changing policy environment. Each revision has attempted to address specific equity or efficiency concerns with the existing methodology, while maintaining the overall objective of recovering the total ISTS ATC from all users in a transparent and non-discriminatory manner. The progressive extension of the renewable energy charge waiver has been the most significant policy variable in successive revisions of the sharing regulations, with the scope and duration of the waiver being contested between renewable energy advocates (who argue for an extended waiver to promote renewable development) and conventional energy interests (who argue that the waiver unfairly concentrates the ISTS cost burden on nonexempt users).

4.3 Transmission Congestion: Management and Pricing

Transmission congestion — the condition in which the desired power flows on the ISTS (driven by the commercial incentives of generators and procurers) exceed the physical capacity limits of specific transmission corridors — is a growing challenge as India's electricity generation mix becomes more concentrated in renewable-rich regions that are distant from major load centres. When congestion exists on a transmission corridor, not all desired power flows can be accommodated simultaneously, and some generation must be reduced or some load must be served from alternative sources. The management of transmission congestion through appropriate regulatory and market mechanisms is important for both economic efficiency (ensuring that the available transmission capacity is allocated to the most valuable uses) and system reliability (ensuring that the transmission system remains within its safe operating limits).

CERC's current approach to transmission congestion management is primarily operational rather than price-based: when the RLDC's day-ahead scheduling process identifies potential congestion on specific transmission corridors, it adjusts the scheduled power flows to stay within the transmission capacity limits, modifying the generation schedules of specific generators to relieve the congestion. This "redispatch" approach to congestion management does not create explicit price signals for congestion (unlike LMP-based nodal pricing, which automatically prices congestion through the spatial price difference between injection and withdrawal nodes), but it ensures that the physical constraints of the transmission system are respected in the day-ahead schedule.

4.4 Competitive Transmission: Private Licensees and TBCB

The Tariff-Based Competitive Bidding (TBCB) framework for transmission projects, under which the right to develop and operate specific ISTS elements is awarded through competitive bidding to the bidder offering the lowest transmission tariff (subject to meeting technical and financial qualification criteria), was introduced to accelerate the pace of ISTS expansion and to bring private capital, expertise, and competitive pressure to bear on the cost of transmission development. CERC's competitive transmission framework specifies the standard documentation for TBCB (including the Request for Qualification, Request for Proposal, Transmission Service Agreement, and Implementation Agreement), the qualification criteria for bidders, the tariff ceiling for each TBCB project (above which bids are non-competitive), and the post-award process for CERC tariff adoption.

The TBCB framework has attracted significant private investment in ISTS assets, with major private transmission companies including Adani Transmission, Sterlite Power, and others developing substantial ISTS portfolios through the competitive transmission process. The regulatory issues arising in the TBCB context include: the treatment of capital cost variations (cost overruns or savings) in the competitive tariff framework (since the competitive tariff is based on the bidder's own cost estimate rather than CERC's normative cost assessment, creating different regulatory risk allocation from the regulated tariff approach used for PGCIL projects); the change-in-law provisions of the Transmission Service Agreement; and the regulatory approach to performance failures by private transmission licensees (including the remedies available to CERC if a licensee fails to achieve the contracted Transmission Availability Guarantee).

4.5 Tariff Disputes and APTEL in Transmission Regulation

Transmission tariff disputes constitute a significant segment of APTEL's regulatory jurisprudence, reflecting the large financial stakes of ISTS transmission tariff determinations and the technical complexity of the capital cost and performance assessment issues that arise in CERC's tariff proceedings for individual ISTS elements. The major categories of transmission tariff disputes that come before APTEL include: capital cost disputes (particularly the treatment of additional capital expenditure incurred after the initial commissioning of a transmission asset, and the prudency assessment of capital costs for transmission projects that experienced significant delays or cost overruns during development); O&M expense disputes (challenging CERC's normative O&M expense levels for different transmission asset categories); and TBCB tariff adoption disputes (challenging the process of competitive transmission bidding or the terms of the Transmission Service Agreement).

APTEL's transmission tariff jurisprudence has established several important principles: the capital cost for regulated transmission assets should include all costs prudently incurred in the development and construction of the asset, subject to the same prudency standards applied in generation tariff proceedings; normative O&M expense parameters should reflect the achievable performance of an efficiently managed transmission system of comparable age, scale, and technology; and the TBCB competitive tariff should be respected by CERC in its adoption proceedings in the same way that competitive generation tariffs are respected under Section 63, with the Commission's role being procedural verification rather than substantive tariff assessment.

CHAPTER FIVE

Inter-State Power Transfer and Regional Coordination

Surplus-Deficit Management, Banking, and the Role of the Power Market

The efficient transfer of electricity between states — from generation-surplus to demand-deficit regions — is one of the primary economic functions of the inter-state transmission system. This chapter examines the mechanisms for inter-state power transfer, regional coordination, and the market instruments that facilitate efficient electricity trade across state boundaries.

5.1 Inter-State Power Transfer: Framework and Instruments

Inter-state electricity transfers in India occur through multiple mechanisms: long-term PPAs under which central generating stations allocate their output to beneficiary states; open access transactions under which states procure additional electricity from generators in other states; inter-state banking arrangements under which states with seasonal surpluses temporarily transfer electricity to states with seasonal deficits; power exchange transactions under which distribution utilities purchase electricity from the DAM and TAM at market-clearing prices; and trading licensee-mediated bilateral transactions that enable flexible short-term procurement. Each mechanism is governed by a distinct legal and regulatory framework, and the choice among mechanisms by distribution utilities reflects a balance between cost, certainty, flexibility, and regulatory risk.

Long-term PPA-based transfers from central generating stations remain the dominant modality for inter-state power transfer by volume, with the central sector generating capacity allocated among states through the Ministry of Power's allocation process. The allocation process specifies the "beneficiary states" for each central generating station and their respective shares of the station's output, and the allocated states enter into PPAs with the generating company (typically through the NTPC, NHPC, or other generating company's model PPA) for their allocated share of the station's capacity. The long-term PPA allocation mechanism provides beneficiary states with firm, predictable supply from centrally planned and developed capacity, but its rigidity (25-year commitments at fixed tariffs) limits the states' ability to respond to changing supply-demand dynamics.

5.2 Banking of Electricity: Legal Framework

Banking of electricity — the arrangement under which a generator or distribution utility deposits surplus electricity into the grid and recovers an equivalent quantity (less applicable banking charges and losses) at a later time — is an important flexibility mechanism for managing seasonal and diurnal variations in renewable energy generation and electricity demand. Banking allows: hydroelectric projects to "store" their surplus monsoon generation in the grid and recover it during the dry season when their own generation is limited; renewable energy open access consumers to carry forward surplus daytime solar generation credits for use during evening peak demand; and inter-state power transfer arrangements to accommodate timing differences between generation availability and consumption requirements.

The legal framework for banking is specified in the SERC open access and wheeling regulations, with each state's SERC specifying the terms and conditions for banking within its jurisdiction (the banking period, the applicable banking charges, the restrictions on cross-state banking, and the settlement mechanism). CERC's inter-state banking framework addresses the coordination of banking arrangements across state boundaries, particularly for renewable energy generators who may have their generating asset in one state and their consumption load (for captive arrangements) or their off-taker (for open access arrangements) in another state. The banking framework for renewable energy has been liberalised under the Green Energy Open Access Rules, 2022, which require SERCs to provide banking facilities for renewable energy open access consumers on specified terms.

5.3 Power Market and Inter-State Commerce

The power exchange market — IEX and PXIL operating under CERC's Power Market Regulations — facilitates efficient inter-state electricity transfer through price-based market clearing mechanisms. The Day-Ahead Market (DAM) auction, in which buyers and sellers across all regions submit price-quantity bids for each 15-minute block of the following day, enables the most valuable generation (lowest marginal cost) to be matched with the highest-value consumption (willing to pay the highest price) across regional boundaries, subject to the transmission capacity constraints of the inter-regional corridors. When the market clearing algorithm finds that the desired power flows at the unconstrained market clearing price exceed the capacity of inter-regional corridors, it applies "area constraints" that separate the national market into regional zones with different market clearing prices, reflecting the transmission congestion premium between zones.

Market Coupling, implemented in 2024 by combining the DAM order books of IEX and PXIL, has improved the efficiency of the power exchange market by creating a deeper, more liquid national market for day-ahead electricity. Market coupling eliminates the price differences between IEX and PXIL that arose from the fragmentation of the exchange market, ensuring that buyers and sellers on both exchanges face the same market clearing price for equivalent delivery conditions. The coupling algorithm aggregates the buy and sell bids from both exchanges and solves for a single national market clearing price (or a set of zonal prices when transmission congestion requires market splitting), providing better price discovery and reducing arbitrage opportunities.

5.4 Regional Energy Balance and Under/Over-Drawl

The Regional Energy Balance (REB) process administered by the RLDCs provides the accounting framework for quantifying each state's net injection or withdrawal from the ISTS in each 15-minute block, and for computing the DSM-based settlement for deviations from approved schedules. The REB involves: metering at all Regional Interface Meters (RIMs) at the state-ISTS boundary; computation of each state's net scheduled injection (or withdrawal) in each 15-minute block; computation of the actual injection (or withdrawal) based on metered data; determination of the deviation (actual minus scheduled); and application of the DSM rate applicable to the relevant grid frequency band in that block.

States that habitually overdraw electricity from the ISTS (consuming more than their approved schedule, aggravating the supply deficit at times of low grid frequency) face high DSM charges, while states that underdraw (consuming less than scheduled at times of surplus, aggravating high frequency) face the opposite financial consequence. The DSM mechanism thus creates a financial incentive for states to manage their consumption in line with their approved schedules, reducing the frequency volatility caused by indisciplined state behaviour. The historic tendency of several states to ignore their scheduling obligations and overdraw electricity — contributing to the chronic high-frequency and low-frequency periods that characterised the Indian grid before the DSM mechanism was strengthened — has been progressively moderated by the improved DSM framework and by the strengthening of POSOCO's enforcement capabilities.

5.5 Emergency Power Transfer and Crisis Management

India's inter-state transmission system includes provisions for emergency power transfer — the rapid mobilisation of available generation in surplus regions to supply emergency shortfalls in deficit regions — that complement the normal commercial mechanisms for inter-state power transfer. Emergency power transfer is managed through the RLDC and NLDC under the emergency protocols specified in the IEGC and the Load Despatch operating procedures. Emergency transfers may involve: emergency procurement of short-term power by a deficit state from surplus states through the Ministry of Power's emergency procurement mechanism; emergency open access on the ISTS (processed within 24 hours rather than the standard processing timeline); and direct despatch instructions from the RLDC to generators in surplus regions to maximise their output for transmission to deficit regions.

CHAPTER SIX

Transmission Planning, Smart Grid, and Future Architecture

National Grid Vision 2047, Smart Transmission, and the Energy Transition

India's transmission infrastructure must evolve rapidly to accommodate the massive increase in renewable energy capacity projected through 2030 and 2047. This chapter examines the planning framework for future transmission investment, the development of smart grid capabilities, and the long-term architecture of India's national electricity network.

6.1 National Electricity Plan: Transmission Investment Requirements

The National Electricity Plan (NEP) 2023–2032, prepared by the Central Electricity Authority, identifies approximately Rs. 9.15 lakh crore of transmission investment required over the planning horizon to support India's renewable energy expansion and to provide adequate transmission capacity for the projected growth in inter-state power flows. This investment requirement is approximately three times the total investment made in ISTS infrastructure over the entire period since PGCIL's establishment in 1989, indicating the scale of the transmission infrastructure challenge. The NEP transmission investment plan includes: inter-regional transmission corridors to handle the growing solar and wind generation from Rajasthan, Gujarat, and Andhra Pradesh; Green Energy Corridors to evacuate renewable energy from new development zones; high-voltage transmission upgrades to accommodate higher power flows on existing corridors; and substation capacity expansion at key ISTS substations.

The timeline for completing the NEP transmission investment is the primary constraint on India's ability to achieve its renewable energy targets. Transmission projects in India typically take 4–7 years from planning to commissioning, including the time required for environmental clearances, forest clearances, Right of Way (RoW) acquisition, equipment procurement, construction, and commissioning. The acceleration of this timeline is a priority for PGCIL, CERC, and the Ministry of Power, with several initiatives underway to streamline the transmission project development process including: standard RoW acquisition protocols; simplified forest clearance procedures for transmission lines; pre-approved tower designs that reduce the design and approvals time; and digital project management systems that improve coordination among the multiple agencies involved in transmission project development.

6.2 High Voltage Direct Current Technology

High Voltage Direct Current (HVDC) transmission technology, while more expensive than AC transmission for shorter distances, offers significant advantages for very long distance bulk power transmission (above approximately 700–800 km), asynchronous interconnections between separate AC grids, and submarine cable applications. India has developed significant HVDC capability, with PGCIL operating several HVDC bipole transmission links including: the Mundra-Mohindergarh ±800 kV, 2,500 MW HVDC line (transmitting Adani Power's Mundra plant output to the Northern Grid); the Champa-Kurukshetra ±800 kV, 3,000 MW HVDC line (one of the world's highest voltage HVDC links, connecting generation in Chhattisgarh to the Northern Grid); and the North-East Agra ±800 kV, 6,000 MW HVDC link (the world's longest HVDC link at commissioning, carrying hydropower from the northeastern states to the northern load centres).

The regulatory treatment of HVDC transmission assets follows the same cost-of-service framework as HVAC assets, with CERC determining the annual transmission charge for each HVDC converter station and transmission line based on the approved capital cost and normative operating parameters. The regulatory challenges specific to HVDC include: the assessment of capital cost for HVDC converter stations, which involve highly specialised equipment with few Indian suppliers and significant variation in cost depending on the voltage level, power rating, and technology specification; the normative availability standards for HVDC systems (which must accommodate the higher complexity of HVDC converters relative to HVAC switchgear); and the O&M expense norms for HVDC equipment (which involves ongoing calibration, maintenance of power electronics, and periodic major overhauls of converter valves).

6.3 Smart Transmission: Technology and Regulation

The digitalisation of India's transmission infrastructure — through the deployment of Phasor Measurement Units (PMUs), advanced SCADA systems, digital substations, and energy management systems (EMS) at POSOCO and the RLDCs — is progressively enhancing the grid management capabilities needed to operate a high-renewable electricity system reliably and efficiently. PMUs, which measure the voltage and current phasors at specific grid nodes with microsecond precision and transmit the data to central monitoring systems in near real-time, provide a dramatically more detailed picture of the dynamic state of the grid than the traditional SCADA-based monitoring systems, enabling more rapid detection of instability precursors and more precise control responses.

PGCIL has been deploying PMUs across the ISTS as part of its Smart Grid initiative, and POSOCO's Wide Area Monitoring System (WAMS) aggregates the PMU data from across the national grid to provide a real-time dynamic view of the grid's stability state. The regulatory framework for smart transmission infrastructure treats PMUs, WAMS, and advanced EMS systems as capital investments in ISTS operational infrastructure, eligible for inclusion in PGCIL's regulated asset base and recovery through the ISTS tariff. CERC's review of PGCIL's capital expenditure plans scrutinises the smart grid investments for consistency with the NEP and for cost-effectiveness, ensuring that the capital cost of transmission digitalisation is prudent and consumer-beneficial.

6.4 Transmission and the Energy Transition

The energy transition — the replacement of coal-based generation with renewable energy, storage, and clean dispatchable alternatives — will fundamentally reshape the pattern of power flows on India's transmission system, creating new infrastructure requirements and making some existing infrastructure redundant. The power flows on the ISTS will progressively shift from coal-mine-proximate thermal generation locations (Jharkhand, Odisha, Chhattisgarh, Madhya Pradesh) to renewable-resource-abundant locations (Rajasthan, Gujarat for solar; Tamil Nadu, Andhra Pradesh for wind; northeastern states for hydro), requiring new transmission capacity in the renewable evacuation corridors while potentially creating excess capacity in the older thermal evacuation routes.

The regulatory framework must accommodate the "stranded transmission asset" risk — the risk that transmission infrastructure developed to serve now-retiring thermal capacity becomes partially redundant and cannot fully recover its approved capital cost through the current transmission tariff mechanism. CERC has addressed this issue by allowing PGCIL to repurpose underutilised transmission assets for new renewable energy evacuation, reducing the stranded asset risk while maximising the utilisation of existing infrastructure. The regulatory treatment of repurposed transmission assets — including the capital cost attribution and tariff implications of converting a thermal evacuation line to a renewable evacuation application — is a developing area of CERC regulatory practice that will become increasingly important as the energy transition accelerates.

6.5 Regulatory Outlook: Transmission Governance for a Clean Grid

The governance of India's electricity transmission system faces transformative challenges as the country's electricity generation mix shifts rapidly towards renewable energy, storage, and new demand categories including EV charging and green hydrogen production. The regulatory framework must evolve on multiple fronts: the ISTS cost sharing methodology must be reformed to ensure fair and sustainable cost recovery as the ISTS user base changes; the transmission planning process must be accelerated and made more adaptive to accommodate the faster pace of renewable energy development; the operational framework must be upgraded to manage the higher variability of a renewable-dominated grid; and the regulatory treatment of new technologies (HVDC, smart grid, storage at the transmission level) must provide appropriate investment signals while protecting consumer interests.

The Forum of Regulators' work on transmission regulation principles, CERC's proactive development of new regulatory frameworks for GNA, market coupling, and ancillary services, and the Ministry of Power's National Electricity Plan provide the policy and regulatory architecture within which these governance challenges must be addressed. The quality of regulatory governance for India's transmission sector will be a critical determinant of the pace and cost of the energy transition: a regulatory framework that enables rapid, cost-effective transmission investment while ensuring fair cost allocation among users will accelerate India's clean energy transition and reduce its cost for consumers and for the economy.

> **Booklet IV Key Takeaways:** India’s electricity transmission regulatory framework rests on the Electricity Act, 2003’s provisions for non-discriminatory open access, CERC’s cost-of-service tariff regulation of ISTS assets, and POSOCO’s operational management of the national grid. The GNA Regulations 2022 have simplified the access framework; market coupling has improved exchange market efficiency; and the NEP 2023–2032 identifies Rs. 9.15 lakh crore of transmission investment needed to support India’s renewable energy expansion. Practitioners must understand the interplay between transmission regulation, market operation, grid code compliance, and the energy transition in advising clients on all aspects of India’s electricity transmission law and governance.

EXTENDED ANALYSIS

Transmission Law: Advanced Topics and Emerging Issues

APTEL Jurisprudence, Grid Security, Renewable Integration, and Cross-Border Developments

A.1 APTEL Jurisprudence on Transmission Regulation

APTEL has developed an important body of jurisprudence on transmission regulatory matters through its review of CERC orders on transmission tariff determination, open access, and grid code compliance. The major principles established through APTEL's transmission jurisprudence include: the definition and application of the "non-discriminatory open access" standard; the regulatory treatment of transmission capital cost overruns; the scope of CERC's adjudicatory jurisdiction over inter-state transmission disputes; and the principles for compensation when transmission capacity constraints prevent open access users from transacting their contracted volumes.

On non-discriminatory open access, APTEL has consistently held that the CTU and transmission licensees must process open access applications on a transparent, consistent, and non-preferential basis. The criteria for granting or refusing open access — availability of transmission capacity, compliance with Grid Code technical requirements, and completion of the prescribed application process — must be applied identically to all applicants without regard to their ownership, commercial affiliation, or the nature of their proposed transactions. Where APTEL has found evidence of discriminatory processing of open access applications (for instance, by applying more stringent technical scrutiny to applications from entities that are competitors of the CTU's affiliates), it has set aside the relevant CERC or CTU decisions and directed reprocessing on non-discriminatory terms.

On capital cost overruns for transmission projects, APTEL has applied the same prudency standard as for generating station cost determination: the CTU or private transmission licensee is entitled to recover the capital cost of its transmission assets, including any overruns, to the extent that the overrun was not caused by the licensee's own imprudence or management failure. Overruns arising from force majeure events (natural disasters, contractor insolvency, geological surprises), from changes in regulatory or environmental requirements during construction, or from changes in scope mandated by the CTU's operational requirements are generally considered prudently incurred and eligible for tariff recovery. Overruns arising from poor project management, under-estimation of costs in the original design, or contractor disputes that could have been avoided by more careful contract management are scrutinised more carefully and may be partially or fully disallowed.

APTEL's jurisdiction over transmission disputes has been clarified through a series of decisions establishing that: disputes about the terms of transmission service agreements (the contracts between the CTU/transmission licensees and ISTS users) fall within CERC's adjudicatory jurisdiction under Section 79(1)(f), not within the general civil court jurisdiction; disputes about the commercial settlement of open access transactions (including DSM-related disputes and energy accounting disputes) also fall within CERC's jurisdiction; and disputes about the technical decisions of the load despatch centres (including despatch instructions and scheduling decisions) are subject to CERC's oversight through its regulatory and adjudicatory powers under the Grid Code.

A.2 Grid Security Events and Legal Consequences

The catastrophic grid collapse of 30–31 July 2012, which resulted in the largest power blackout in history affecting approximately 620 million people across 22 states, provides a defining case study in the legal and regulatory consequences of grid security failures. The Report of the Committee to Enquire into Grid Disturbances (the "Grid Disturbance Committee" report), submitted to the Ministry of Power in August 2012, identified the primary causes of the two successive grid collapses as: chronic overdrawal by several states beyond their approved ISTS schedules; inadequate reserve margins in the Northern Regional Grid at the time of the disturbances; inadequate governor response from generating units that failed to respond properly to frequency deviations; and coordination failures between the RLDC, NLDC, and state load despatch centres.

The legal and regulatory consequences of the 2012 grid collapse included: CERC issuing show-cause notices to states and distribution utilities responsible for chronic overdrawal, leading to penalty proceedings; CERC issuing directions to PGCIL to upgrade its RLDCs' real-time monitoring and control systems; CERC strengthening the enforcement of governor control requirements through amendments to the IEGC; the Ministry of Power directing POSOCO to develop enhanced grid security protocols and emergency response procedures; and CERC and the Forum of Regulators initiating consultations on the reform of the Deviation Settlement Mechanism to provide stronger financial incentives for grid discipline.

The institutional and regulatory reforms implemented after the 2012 grid collapse have significantly improved India's grid security. The DSM mechanism revision (replacing the earlier UI mechanism) introduced stronger and more differentiated frequency-based price signals for grid discipline. CERC's enhanced enforcement of governor control requirements has improved the automatic frequency response capability of the generating fleet. POSOCO's investment in advanced grid management tools, including wide-area monitoring systems and improved energy management software, has strengthened its ability to detect and respond to grid disturbances before they escalate to full grid collapse. And the improved communication protocols between the NLDC, RLDCs, and SLDCs have reduced the coordination failures that contributed to the 2012 events.

A.3 Renewable Energy Integration: Grid Management Challenges

The rapid increase in variable renewable energy's share of India's electricity generation is creating new grid management challenges that require both technical adaptations to the grid infrastructure and regulatory framework and commercial adaptations to the market and despatch arrangements. The key technical challenges include: managing the "duck curve" in the net load (the characteristic shape of the residual load after subtracting variable renewable generation from total demand, which shows steep ramping requirements in the morning as solar generation rises and in the evening as solar generation falls); managing the increasing frequency volatility arising from the replacement of conventional synchronous generators (which provide inertia and governor response) with inverter-based renewable resources (which have little or no natural inertia and may not provide governor response without specific control system programming); and managing the spatial concentration of renewable resources, which creates large, directional power flows on specific transmission corridors that can stress corridor capacity and require active management.

POSOCO has responded to these challenges through a combination of operational improvements and regulatory changes: enhanced day-ahead and intra-day forecasting of wind and solar generation, using weather-based models that predict generation output with increasing accuracy as forecast horizons shorten; development of ramping protocols that ensure sufficient flexible generating capacity is available to manage the expected ramp-up in renewable generation in the morning and the ramp-down in the evening; active management of inter-regional transmission flows to manage renewable energy evacuation from surplus regions to deficit regions; and development of the ancillary services framework to procure and compensate the flexibility services needed for grid balance as renewable penetration grows.

The regulatory framework for renewable energy integration has been developed through a series of CERC consultations and regulations addressing: the technical requirements for renewable energy generators to provide ancillary services (including reactive power support, synthetic inertia, and fast frequency response); the market mechanisms for procuring and compensating these services (the ancillary services market and the Real-Time Market); the planning requirements for transmission expansion to accommodate projected renewable energy growth; and the storage procurement framework that provides the flexible capacity needed as storage becomes cost-competitive. These regulatory developments are collectively building the framework for a high-renewable, low-carbon electricity system that can maintain the reliability and stability of supply that India's consumers and its economy require.

A.4 Underwater and Underground Transmission: Emerging Technology

The development of offshore wind energy in India — and potentially of offshore solar platforms in the future — requires underwater transmission infrastructure to bring the offshore-generated electricity to the onshore grid. High Voltage Direct Current (HVDC) submarine cable technology is the standard approach for offshore wind transmission over distances greater than approximately 50–80 km (beyond which the capacitive charging current of long AC submarine cables reduces the effective transmission capacity). The development of India's first offshore wind projects will require HVDC submarine cables connecting the offshore wind platforms to onshore HVDC converter stations, creating new categories of regulated transmission assets with novel operational and risk characteristics.

CERC's regulatory framework for offshore transmission infrastructure is still being developed, with MNRE's guidelines on offshore wind development providing the initial policy framework. The key regulatory questions for offshore transmission include: whether the offshore transmission infrastructure should be included in the offshore wind developer's project cost (making it subject to competitive tariff discovery) or developed as a separate regulated ISTS element (subject to CERC's cost-of-service tariff regulation); the applicable technical standards and performance requirements for submarine HVDC cables (which must be specified by the CEA under Section 73(b) of the Act); and the liability framework for offshore transmission failures (which can cause prolonged unavailability of large amounts of offshore wind generation capacity, imposing significant financial losses on the offshore wind developer and the procuring distribution utilities).

Underground transmission cables, while more expensive than overhead lines, are increasingly being used for high-density urban areas (where overhead line towers are impractical) and for sensitive ecological areas (where overhead lines would cause unacceptable wildlife or environmental impacts). PGCIL and state transmission utilities have developed experience with underground transmission cables at 220 kV and 400 kV voltage levels, and CERC's tariff framework accommodates underground cables as a legitimate category of regulated transmission asset with appropriate cost norms for their higher capital cost relative to overhead lines. The development of HVDC underground cables for metropolitan area transmission networks is an emerging technology area that may see significant deployment in India as the urban distribution networks of major cities are restructured to accommodate rooftop solar, EV charging, and increased demand densities.

A.5 Right of Way: Legal Framework for Transmission Infrastructure

The acquisition of Right of Way (RoW) for transmission lines — the legal right to construct, maintain, and operate overhead transmission towers and cables across private land and public land — is one of the most challenging practical aspects of developing new electricity transmission infrastructure in India. The legal framework for RoW acquisition for electricity transmission lines is primarily governed by the Indian Telegraph Act, 1885 (which applies to "telegraph lines" including electricity transmission lines under Section 10A of the Act), the Electricity Act, 2003 (which provides supplementary powers for the transmission licensee to survey, erect, and maintain transmission lines), and various state laws and court orders relating to compensation for land use for transmission purposes.

The compensation payable to landowners for transmission RoW has been a source of significant litigation and project delay. Under the Telegraph Act and the Electricity Act, transmission licensees have the statutory authority to erect transmission towers and string cables across private land (including agricultural land) after providing notice to the landowner and paying appropriate compensation. The compensation is typically assessed as the agricultural or market value of the strip of land permanently affected by the transmission towers, plus a percentage of the annual value of crops or income disrupted during construction. Land owners, particularly in agricultural states, have frequently challenged the adequacy of compensation awarded under the statutory framework, leading to lengthy disputes before courts and special tribunals that can significantly delay the commissioning of transmission projects.

The RoW challenge is particularly acute for new transmission lines in densely populated agricultural areas (such as the Indo-Gangetic plains of Uttar Pradesh, Punjab, and Haryana), where virtually all land is privately owned and actively cultivated and the prospect of transmission towers on the land is strongly resisted by landowners. PGCIL has developed innovative approaches to managing the RoW challenge including: pre-consultation with village communities and local authorities before the land survey and notification process; community development programmes in project-affected areas to build social acceptance; use of compact tower designs that minimise the footprint of individual towers; and the use of aerial bundled cables or underground cables in particularly sensitive or contested areas (though at higher cost). These approaches, while not eliminating RoW challenges, have improved PGCIL's ability to manage the social dimensions of transmission project development and to commission projects within acceptable timeframes.

A.6 Energy Storage at the Transmission Level

The deployment of large-scale energy storage at the transmission level — primarily pumped hydro storage (PHS) and utility-scale battery energy storage systems (BESS) connected to ISTS substations — is an emerging priority for India's grid management as renewable energy penetration grows and the need for dispatchable flexibility increases. CERC has been developing the regulatory framework for transmission-level storage through its consultations on the ancillary services market, the GNA Regulations 2022 (which include specific provisions for Energy Storage Systems), and through project-specific tariff determinations for storage projects procured by SECI and distribution utilities.

The regulatory classification of transmission-level storage has significant implications for cost recovery. If a large-scale BESS is classified as a "transmission asset" (because it is primarily providing grid stabilisation and balancing services to the ISTS), it could be included in PGCIL's regulated asset base and its cost recovered through the ISTS transmission tariff. Alternatively, if it is classified as a "generation asset" (because it can produce electricity for sale), it would be subject to competitive tariff discovery under Section 63 or cost-based tariff determination under Section 62. CERC's current approach has been to treat standalone storage projects procured by SECI or distribution utilities under competitive bidding as generation/storage assets subject to Section 63 adoption, while treating storage that is functionally part of the transmission system (such as co-located substation batteries providing voltage support and frequency response) as potentially eligible for treatment as transmission infrastructure.

Pumped hydro storage (PHS), which provides very large-scale (GW) and long-duration (hours to days) energy storage at lower per-unit cost than battery storage, is particularly important for India's long-term grid management requirements. The 2022 National Hydro Policy and the Ministry of Power's framework for pumped storage development provide the policy support for accelerating PHS development. CERC has addressed the regulatory treatment of PHS projects in its tariff proceedings, establishing that PHS projects with storage and generation functions should be treated as regulated hydro generating stations for tariff purposes, with the pumping cost (the cost of electricity used to pump water to the upper reservoir) treated as an operating cost recovered through the approved tariff. The interaction between the PHS project's pumping operations (which make it a large electricity consumer) and the electricity market (from which it purchases pumping energy) creates complex commercial and regulatory relationships that require careful framework design.

A.7 Future of the Indian Grid: National Grid Vision 2047

India's National Grid Vision 2047, developed by the Ministry of Power and PGCIL in consultation with the CEA, CERC, and the state governments, provides a long-term roadmap for the development of India's electricity transmission infrastructure to support the country's development aspirations and climate commitments by the centenary of independence. The Vision envisages: a fully synchronous national AC grid operating at 765 kV and above, with adequate inter-regional interconnection capacity to enable efficient power flow from any region to any other; a network of HVDC superhighways providing dedicated high-capacity corridors for bulk renewable energy transfer from major solar and wind resource zones; deep integration of the Indian grid with the South Asian regional power market through strengthened cross-border interconnections; and comprehensive digitalisation of grid monitoring, control, and protection through advanced technologies including artificial intelligence-based grid management systems, wide-area protection schemes, and digital twin-based planning tools.

The regulatory framework required to support the National Grid Vision includes: a long-term transmission investment programme approved by CERC and funded through the regulated tariff framework; a comprehensive RoW acquisition framework that balances the need for expeditious transmission development with the rights of landowners and affected communities; technology-specific regulatory frameworks for HVDC transmission, underground cables, and smart grid infrastructure; and enhanced coordination between CERC, the SERCs, POSOCO, and the state load despatch centres for the operational management of the evolving national grid. The Forum of Regulators' role in developing common regulatory standards and coordinating the actions of the multiple regulatory bodies involved in grid governance is particularly important for the achievement of the National Grid Vision's objectives.

A.8 Cross-Border Transmission Interconnection

India's transmission interconnection with its South Asian neighbours — Nepal, Bhutan, Bangladesh, and Myanmar — is a growing and strategically important dimension of the country's electricity sector governance. The development of cross-border transmission infrastructure enables: the import of hydroelectric energy from Nepal and Bhutan (which have large surplus hydropower potential relative to their domestic demand); the export of electricity to Bangladesh (which has a growing electricity demand deficit that India can help meet through competitive supply); and the future development of a regional power market in South Asia that could significantly improve the efficiency of electricity supply across the region by enabling load balancing across national boundaries.

The regulatory framework for cross-border transmission infrastructure involves: bilateral agreements between India and each neighbouring country specifying the ownership, operation, and maintenance responsibilities for the cross-border transmission links; CERC's oversight of the cross-border transmission assets on the Indian side under its jurisdiction over ISTS assets; and commercial settlement arrangements for cross-border power flows. PGCIL develops and operates the Indian side of cross-border transmission links in most cases, with the costs of the cross-border links included in PGCIL's regulated asset base and recovered through the ISTS tariff framework. The non-Indian portions of cross-border transmission assets are owned and operated by the relevant national transmission utility of the neighbouring country, under that country's regulatory framework.

A.9 Key Regulatory Challenges in Transmission Governance

The governance of India's electricity transmission system faces several chronic regulatory challenges that have resisted resolution despite sustained attention from CERC, POSOCO, and the Ministry of Power. These challenges reflect the inherent complexity of regulating a large, technically sophisticated, and commercially significant infrastructure system in a federal polity with multiple levels of regulatory authority and diverse stakeholder interests.

The most persistent challenge is the coordination between the ISTS (regulated by CERC) and the intra-state transmission systems (regulated by the SERCs) in a way that ensures the overall transmission system operates as an integrated whole rather than as a collection of separately optimised subsystems. The coordination challenge arises because: the ISTS and intra-state transmission systems are physically interconnected and the power flows on each affect the other; the regulatory frameworks applicable to each system are different in detail and sometimes in principle; the commercial arrangements for power flowing across the ISTS-state transmission boundary involve both CERC-regulated and SERC-regulated elements; and the investment planning and development timelines of the two systems must be coordinated to avoid transmission bottlenecks at the ISTS-state interface.

A second persistent challenge is the enforcement of the open access framework against resistance from state governments and distribution utilities who are reluctant to facilitate the exit of large industrial consumers from their regulated supply. Despite CERC's and APTEL's consistent enforcement of the non-discrimination principle, many states have used informal administrative pressure, delays in application processing, and creative interpretation of capacity constraint provisions to effectively impede open access for large consumers, particularly in periods of power shortage when the departure of large consumers from regulated supply could worsen the utility's financial position. Strengthening the regulatory enforcement of open access — through improved monitoring, clearer standards for capacity constraint claims, and stronger penalties for unjustified denials — is a priority for CERC and APTEL in the ongoing development of the competitive electricity market.

A third challenge is the management of the transmission system's increasing complexity as the generation mix diversifies and the volume of renewable energy, storage, and distributed resources grows. The operational and planning tools used by POSOCO and the RLDCs were primarily designed for a grid dominated by large, controllable synchronous generators, and they require significant upgrading to manage the stochastic variability of high renewable penetration. The investment in advanced grid management technology — PMUs, wide-area monitoring, advanced forecasting, real-time stability analysis, and AI-based optimisation — is underway but must be accelerated to keep pace with the rapid growth of renewable energy. The regulatory framework must create appropriate investment incentives for this technology modernisation while ensuring that the costs of digitalisation are prudently incurred and equitably shared among transmission system users.

> **Booklet IV Comprehensive Summary:** India's transmission regulatory framework — spanning the Electricity Act, 2003, the IEGC, the GNA Regulations 2022, CERC's tariff and adjudicatory jurisdiction, and POSOCO's operational management of the national grid — provides the legal and institutional architecture for one of the world's largest and most complex electricity transmission systems. The framework has enabled the development of India's synchronous national grid, the growth of the competitive electricity market, and the progressive integration of renewable energy. The challenges of the energy transition — massive renewable energy evacuation requirements, new storage technologies, cross-border market integration, and grid digitalisation — require continued regulatory innovation and investment to ensure that India's transmission infrastructure remains adequate for the demands of a clean, competitive, and resilient electricity system.

EXTENDED ANALYSIS II

Transmission Regulation: Deeper Analysis

Tariff Disputes, Grid Security Law, Interconnection Standards, Emerging Technologies

B.1 Transmission Tariff: Detailed Jurisprudence

CERC's tariff determinations for individual ISTS transmission elements involve detailed analysis of capital costs, O&M expenses, and normative parameters. The most contested aspect has historically been the treatment of additional capitalisation: costs incurred by PGCIL or private transmission licensees after the initial commissioning of a transmission element, for purposes such as equipment replacement, capacity augmentation, and technology upgrades. CERC's position is that additional capitalisation is allowable in the tariff base where it is technically necessary for maintaining or improving the transmission element's performance and is prudently executed at reasonable cost. The burden of demonstrating necessity and prudency lies with the licensee seeking to include the additional capitalisation in its tariff base.

The treatment of transmission system losses in the ISTS framework has also been addressed by CERC and APTEL. The ISTS transmission losses — the electrical energy dissipated as heat in transmission conductors during power transmission — are measured through the ISTS energy accounting process and allocated among ISTS users in proportion to their scheduled injection and withdrawal quantities. Losses are recovered not through a financial charge but through a "Loss Allocation Mechanism" under which users are required to inject additional energy to compensate for the allocated losses. The normative loss percentages specified in CERC's regulations represent the technically expected losses for different transmission voltage levels and corridor lengths, and deviations from the normative loss levels (arising from actual network conditions, loading patterns, and equipment performance) are settled through the DSM mechanism.

B.2 State Load Despatch Centres: Regulatory Status and Functions

The State Load Despatch Centre (SLDC) designated under Section 31 of the Electricity Act, 2003 occupies a unique institutional position in India's electricity governance architecture. The SLDC must be a separate, neutral entity not engaged in the business of generation, transmission, or distribution within the state, with the objective of ensuring that it can discharge its load despatch function impartially without favouring any commercial interest. The SLDC is responsible for: scheduling intra-state generation (including state sector generating stations, IPPs connected to the intra-state transmission system, and the state's share of central sector generation) to meet intra-state demand; coordinating with the RLDC on the state's injection into and withdrawal from the ISTS; and managing intra-state system balancing through the intra-day revision process.

The regulatory oversight of SLDCs involves both CERC (which has jurisdiction over the SLDC's interactions with the ISTS) and the SERC (which has jurisdiction over the SLDC's intra-state functions). The SERC specifies the State Grid Code governing intra-state scheduling and despatch, consistent with the IEGC's framework but with state-specific adaptations for the particular characteristics of the state's generation mix and network topology. The SLDC's operations are funded through a surcharge on the electricity wheeling through the state transmission system, approved by the SERC as part of the state transmission tariff proceedings.

B.3 India-Nepal Power Trade: Legal and Regulatory Framework

The electricity trade relationship between India and Nepal has grown substantially in recent years, driven by the development of Nepal's considerable hydroelectric potential and the recognition by both countries that energy cooperation can be mutually beneficial: Nepal has surplus hydroelectric generation during the monsoon and post-monsoon season (when river flows are high) and a deficit in the dry season (when flows are low), while India has the opposite pattern in many regions. The bilateral trade framework enables Nepal to export its surplus monsoon generation to India (earning foreign exchange revenue) and import electricity from India during the dry season (reducing its own shortage).

The Power Trade Agreement (PTA) between India and Nepal, signed in 1971 and supplemented by more recent exchange of letters and protocols, provides the bilateral legal framework for electricity trade. The India-Nepal power trade is implemented commercially through NVVN as the Indian purchasing and selling entity, with NVVN procuring electricity from Nepal's generators (particularly the NEA, Nepal Electricity Authority) and selling it to distribution utilities in the northern states at agreed terms. The technical framework for cross-border power flows is managed by PGCIL (which operates the Indian interconnection substations) and NEA (which operates the Nepal interconnection points), with the RLDC and the equivalent Nepal despatch centre coordinating the scheduling of cross-border flows.

B.4 Technology Standards for Grid-Connected Assets

The Central Electricity Authority's technical standards for grid-connected assets, issued under Section 73(b) of the Electricity Act, 2003, specify the minimum technical requirements for generating stations, Energy Storage Systems, HVDC systems, and other assets seeking connectivity to the ISTS. These standards are binding on all entities seeking ISTS connection and are enforced through the GNA application review process administered by PGCIL as CTU. The principal technical standards relevant to ISTS connectivity include: the Standards for Construction of Electrical Plants and Electric Lines (specifying design, material, and equipment requirements for generation and transmission infrastructure); the Standards for Connectivity to the Grid (specifying governor response, reactive power capability, protection relay settings, and communication interface requirements for generating stations and storage systems); and the Standards for Smart Electricity Meters (specifying accuracy, communication, and tamper detection requirements for the energy meters used at ISTS boundary points).

The rapid evolution of inverter-based resources — solar PV, wind turbines with full power conversion, and battery storage — has required the CEA to develop new technical standards specifically for these technologies. Inverter-based resources have different technical characteristics from conventional synchronous generators in terms of: fault current contribution (lower, since inverters have current-limiting capabilities that prevent the large fault currents provided by synchronous generators); frequency response (inherently zero natural inertia, though inverters can be programmed to provide synthetic inertia and fast frequency response); reactive power capability (which can be controlled more flexibly than synchronous generators but may be limited under certain operating conditions); and the interaction with the grid voltage and frequency (inverters can destabilise the grid if not properly designed and controlled, particularly in weak grid areas with high penetrations of inverter-based resources).

B.5 Transmission and Consumer Protection

The transmission regulatory framework intersects with consumer protection in several specific ways that practitioners advising large industrial and commercial consumers must understand. The most direct consumer protection issue in transmission regulation is the non-discrimination obligation for open access, which protects consumers' right to access the transmission network on equal terms regardless of their size, ownership, or commercial affiliations. The enforcement of this obligation through CERC's and APTEL's regulatory and adjudicatory processes provides consumers with a legally enforceable right to non-discriminatory transmission access.

The reliability standards applicable to the ISTS — the Transmission Availability Guarantee (TAG) specified in PGCIL's and private transmission licensees' tariff orders — create a regulatory obligation on transmission licensees to maintain their assets in a state of reliability consistent with the approved performance benchmarks. Where a transmission licensee's assets fall below the TAG due to inadequate maintenance or operational failures, CERC can reduce the licensee's annual transmission charge (through the availability-based tariff mechanism) and can in extreme cases initiate regulatory proceedings to address the performance failure. The TAG mechanism thus provides indirect consumer protection by ensuring that the transmission system on which consumers depend for electricity supply is maintained to adequate reliability standards.

B.6 Evolving Market Architecture and Transmission Implications

The evolution of India's electricity market from a predominantly bilateral contract structure towards a more exchange-based and real-time market creates specific implications for the transmission regulatory framework. As more electricity is traded through the power exchanges (rather than under long-term bilateral PPAs), the pattern of power flows on the ISTS becomes less predictable and more volatile: exchange-based transactions can create large, rapid changes in the direction and magnitude of power flows as market prices change, requiring the ISTS to accommodate a wider range of flow scenarios than it was designed for under the bilateral PPA framework.

Market coupling — the integration of IEX's and PXIL's Day-Ahead Markets into a single, nationally-cleared auction — creates specific transmission implications because the coupling algorithm takes into account the transmission capacity constraints of the inter-regional corridors when clearing the market. When transmission capacity is sufficient for all desired power flows, the market coupling produces a single national market clearing price. When transmission capacity is constrained, the coupling algorithm splits the national market into regional zones with different prices, with the zonal price difference reflecting the congestion cost on the constrained corridor. This price-based congestion management provides implicit signals for efficient transmission investment (by revealing the economic value of relieving specific congestion points) and for efficient location decisions by generators and large consumers.

Looking forward, the development of a Capacity Market for India would require significant adaptation of the transmission regulatory framework. A capacity market in which generating companies are compensated for maintaining available capacity would need to specify the geographical boundaries of the capacity zones (reflecting the transmission constraints that limit the effective contribution of capacity in one region to meeting peak demand in another region), the capacity adequacy standards applicable to each zone, and the transmission upgrades needed to expand zone boundaries as new transmission capacity is built. The design of capacity zones for India — given the complexity of the national grid and the very different generation and demand characteristics of different states and regions — would require sophisticated transmission modelling and extensive stakeholder consultation, making it a long-term regulatory development objective rather than a near-term priority.

Booklet IV Supplementary Summary: This extended analysis has examined the deeper dimensions of India's transmission regulatory framework, including APTEL's jurisprudence on transmission tariff disputes, the legal consequences of the 2012 grid collapse, the challenges of renewable energy integration, emerging technologies including HVDC and underwater cable, RoW acquisition law, storage at the transmission level, the National Grid Vision 2047, cross-border transmission frameworks, technology standards, and the implications of the evolving market architecture for transmission regulation. Together with the core chapters, this booklet provides a comprehensive reference for practitioners advising on all aspects of Indian electricity transmission law and governance.