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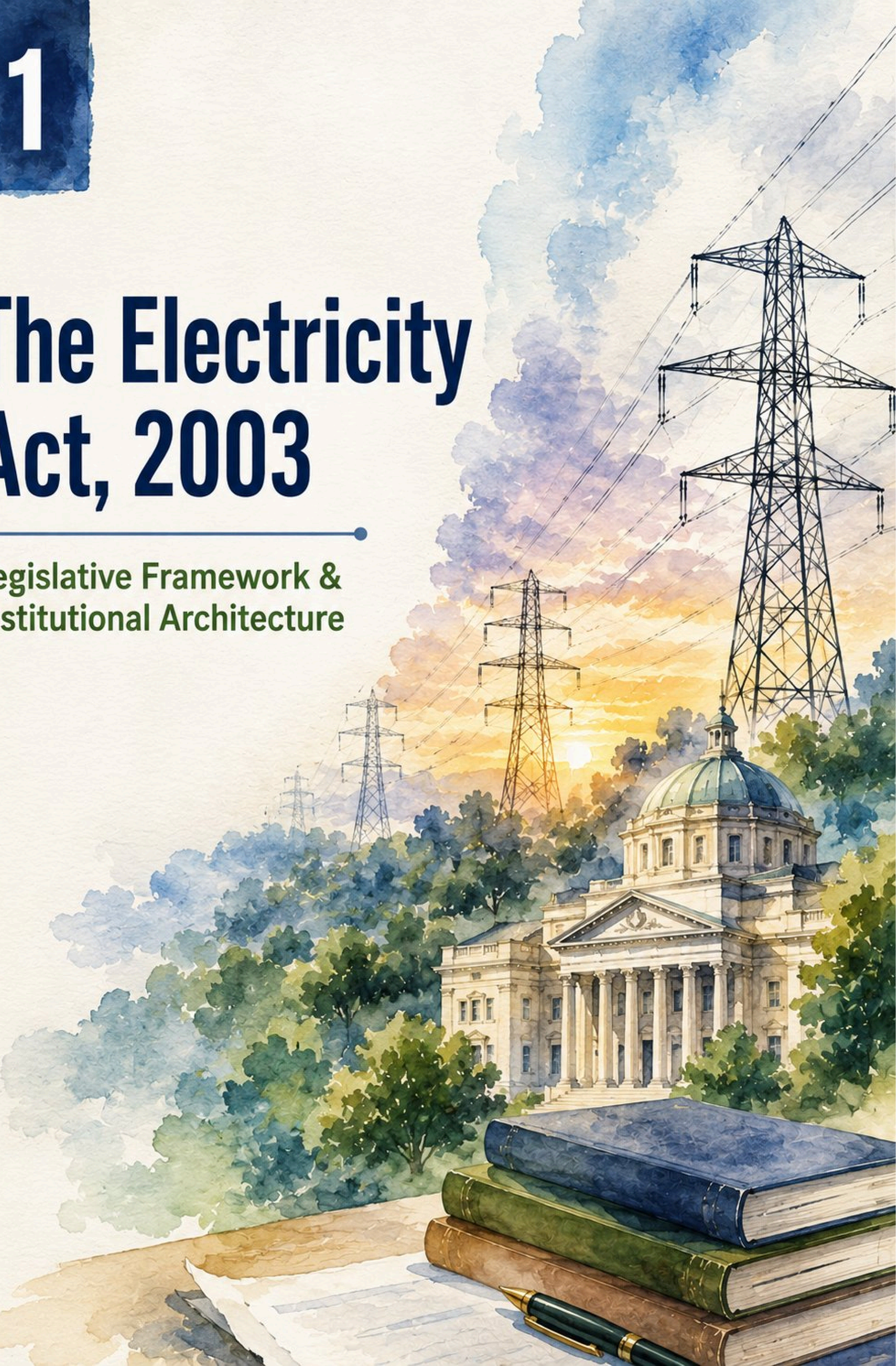
The Electricity Act, 2003

Legislative Framework & Institutional Architecture



The Electricity Act, 2003

Legislative Framework & Institutional Architecture

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CHAPTER ONE

Historical Evolution of Electricity Legislation in India

From Colonial Administration to the Modern Regulatory State, 1910–2003

The Indian electricity sector has been shaped by successive waves of legislative and institutional reform spanning more than a century. Understanding this historical trajectory is essential for comprehending the current regulatory architecture established by the Electricity Act, 2003 and the context in which India's electricity regulatory institutions operate today.

1.1 The Colonial Legal Architecture: Indian Electricity Act, 1910

The Indian Electricity Act, 1910, enacted during the British colonial administration, constitutes the foundational statutory instrument governing the supply and use of electrical energy in pre-independence India. Enacted against the backdrop of rapidly expanding industrial and urban electricity demand particularly in the major commercial centres of Bombay, Calcutta, and Madras, the 1910 Act sought to create a basic regulatory framework for the nascent electricity sector while preserving the dominant role of the provincial state as a provider and controller of essential infrastructure services. The Act was substantially modelled on the British Electric Lighting Act, 1882 and its successor legislation, adapted to the administrative and constitutional conditions of colonial India.

The 1910 Act established a licensing framework under which private entities could obtain licences from the provincial government to supply electricity within defined geographical areas. These licences granted the licensee a degree of exclusivity within the licensed area, a feature that would persist through successive legislative regimes and continue to shape the structure of electricity distribution in India for nearly a century. The Act vested oversight authority in the provincial governments, which exercised supervisory jurisdiction over licensees through technical and financial conditions embedded in individual licence instruments. The conditions of licence were not standardised through regulations; rather, they were negotiated and specified individually for each licensee, creating a heterogeneous regulatory landscape that varied significantly across different provinces and licenced areas.

The 1910 Act's primary architectural features included: provisions for the grant, modification, and revocation of licences for electricity supply; technical standards for electrical installations and systems including requirements for earthing, insulation, and protection of electrical lines; provisions for the compulsory acquisition of undertakings by government after a specified number of years (typically 20-25 years) at a price determined by arbitration; consumer protection provisions including obligations on licensees to supply electricity on reasonable conditions and at reasonable tariffs; and penal provisions for theft and unauthorised abstraction of electricity, recognising early that the abstraction of electricity without payment would be a persistent regulatory challenge.

The regulatory framework created by the 1910 Act was administered primarily through the provincial Electrical Inspector, a technical official responsible for safety and standards compliance. The Electrical Inspector system, while adequate for the relatively limited scale of the early electricity sector, was not designed to address the economic regulation of electricity pricing or the systemic planning of electricity supply infrastructure. These limitations became increasingly apparent as the electricity sector expanded in scale and complexity through the 1920s, 1930s, and 1940s, driven by the growth of industrial demand from cotton mills, engineering works, mining operations, and railways.

The private utility model that operated under the 1910 Act was characterised by geographic fragmentation, with individual utilities serving specific cities or industrial areas without coordination or integration with neighbouring systems. This fragmentation precluded the realisation of economies of scale in generation and made it impossible to balance supply and demand across wider geographic areas. The absence of a framework for inter-utility power exchange or interconnection meant that each utility had to maintain its own reserve capacity independently, leading to inefficiency and high costs. These structural deficiencies of the private utility model under the 1910 Act provided much of the rationale for the nationalisation of electricity supply under the 1948 legislation.

Despite its limitations, the 1910 Act established several legal principles and institutional features that would endure, in modified form, through successive legislative regimes. The concept of a geographically defined “area of supply” within which a licensee had the exclusive right and obligation to supply electricity was inherited by the 1948 Act and retained, in substantially modified form, by the Electricity Act, 2003. The consumer protection principle — that licensees had a legal obligation to supply electricity on reasonable terms — was also carried forward, though its content and enforceability were transformed by the creation of regulatory commissions with the power to determine tariffs and standards of service. The 1910 Act's compulsory acquisition provisions were superseded by the nationalisation model of the 1948 Act, but the underlying principle of public control over essential electricity infrastructure was preserved in the new legislative regime.

1.2 The Electricity (Supply) Act, 1948: Centralisation and State Control

The period immediately following Indian independence witnessed a fundamental reorientation of the electricity sector towards state ownership and central planning. The Electricity (Supply) Act, 1948, represented the definitive expression of the Nehruvian developmental state's approach to infrastructure governance: centralised planning, public ownership, vertically integrated utilities operating as statutory monopolies within defined territorial jurisdictions, and a philosophy that regarded electricity as a public good whose supply could not be safely entrusted to the market. This legislative philosophy was consistent with the broader economic framework of the early post-independence period, in which the state was assigned the leading role in directing industrial development and allocating scarce capital to priority sectors.

The most significant institutional innovation of the 1948 Act was the creation of State Electricity Boards (SEBs) as statutory bodies responsible for the generation, transmission, and distribution of electricity within each state. The SEBs were vested with the exclusive right to supply electricity within their respective territories, displacing the earlier system of private sector licensees except in areas where private distribution licensees were already operating under pre-existing arrangements. The vertically integrated structure of the SEBs — combining generation, transmission, and distribution under a single administrative entity — was considered administratively efficient and consistent with the central planning philosophy of the era. The perceived advantages included unified accountability, coordinated system planning, and the ability to cross-subsidise economically unviable supply areas through profits from commercially viable segments.

The 1948 Act established the Central Electricity Authority (CEA) as the paramount technical authority for the electricity sector at the national level. The CEA was charged with: advising the Central Government on matters relating to the generation, supply, and use of electricity; the development of national electricity plans for the systematic development of electricity supply on a national basis; preparation of annual power surveys of the country with respect to the availability and use of electricity; formulation of specifications for electrical plants and lines; and advising on the organisation of the electricity industry and the improvement of its operations. The CEA represented the apex of technical planning authority for the electricity sector and its recommendations carried significant weight in shaping investment decisions and operational standards across the sector.

The regional grid structure established under the 1948 Act — comprising the Northern, Western, Southern, Eastern, and North-Eastern regional grids — represented an important attempt at coordinating electricity systems across multiple states. Regional Electricity Boards were established to facilitate coordination of these regional grids, and inter-state power exchange arrangements were facilitated through the regional framework. This regional coordination mechanism laid the foundation for the eventual development of a national grid interconnecting all five regions — a development that would come to fruition in the period 2012–2014 with the interconnection of the Southern Regional Grid with the rest of the country, creating a truly national synchronous electricity grid.

The financial architecture of the 1948 Act required the State Electricity Boards to conduct their operations on a "not-for-profit but not-for-loss" basis, meaning that their tariffs should cover the full cost of supply including a reasonable return on capital. This requirement was embedded in Section 59 of the 1948 Act and was intended to prevent the SEBs from either making commercial profits (which would be inconsistent with their public service character) or running persistent losses (which would burden state finances). In practice, however, the Section 59 requirement was honoured in the breach by most State Electricity Boards throughout the post-independence period.

The deterioration of the financial position of the State Electricity Boards was a progressive and accelerating process. Politically determined tariff levels consistently fell below the cost of supply, particularly for agricultural consumers who received heavily subsidised or even free electricity in many states. Transmission and distribution losses escalated due to theft, metering deficiencies, and inadequate investment in network maintenance. Operational efficiency stagnated due to overstaffing, poor management practices, and the absence of competitive pressure. The cross-subsidisation of agricultural and domestic consumers through higher tariffs on industrial and commercial consumers — while politically expedient — distorted price signals and undermined the competitiveness of Indian industry. By the late 1980s and early 1990s, the aggregate losses of the SEBs had become a significant burden on state finances, with several states having to provide large budgetary transfers to keep their SEBs operational.

1.3 The 1991 Economic Liberalisation and Power Sector Reform

The economic reforms initiated in July 1991, while primarily directed at the industrial, financial, and trade sectors, had profound and lasting consequences for the electricity sector. Three interconnected developments in the early 1990s created the conditions for fundamental electricity sector reform: the severe electricity shortage, with demand exceeding available supply by 20–30 per cent in many parts of the country; the deteriorating financial condition of the State Electricity Boards, which were unable to fund capacity expansion from their own resources; and the liberalisation of the broader economy, which created pressure for reform of infrastructure sectors seen as constraining industrial competitiveness.

The Government of India's October 1991 policy statement on the power sector announced the opening of electricity generation to private investment, including foreign direct investment. This represented a decisive departure from the post-independence model of state-controlled electricity supply. The policy statement was given legal effect through amendments to the Electricity (Supply) Act, 1948 and the Indian Electricity Act, 1910, which removed barriers to private investment in generation and established a legal framework for independent power producers to enter into long-term power purchase agreements with State Electricity Boards. The policy statement also encouraged the restructuring and corporatisation of SEBs to improve their operational and financial performance.

The Independent Power Producer (IPP) initiative of the early 1990s attracted significant investor interest but ultimately produced deeply disappointing results. The structural problems were fundamental: in the absence of an independent regulatory authority, power purchase agreements between private generators and State Electricity Boards were negotiated directly and without regulatory oversight, creating opportunities for economic rents and leaving distribution utilities exposed to uneconomic obligations. The most significant failure was the Dabhol Power Project in Maharashtra, promoted by the Enron Corporation, which entered into a power purchase agreement that proved unaffordable for the Maharashtra State Electricity Board and ultimately led to a prolonged contractual and legal dispute. The Dabhol saga exposed the fundamental inadequacy of the existing legal and regulatory framework for facilitating private sector investment in electricity generation.

The Orissa Electricity Reform Act, 1995, enacted by the state legislature of Orissa (now Odisha), represented the first systematic attempt to comprehensively reform the structure of the electricity sector at the state level. The Orissa reforms were informed by the international experience of electricity sector restructuring in the United Kingdom, Australia, and elsewhere, adapted to the specific conditions of an Indian state. The central elements of the Orissa reforms were: the corporatisation and unbundling of the Orissa State Electricity Board into separate generation, transmission, and distribution entities; the creation of the Orissa Electricity Regulatory Commission (OERC) as an independent statutory body with the power to determine tariffs and regulate the operations of electricity utilities; the introduction of competitive tendering for power purchase; and the eventual privatisation of distribution in some areas. The OERC was the first independent electricity regulatory commission in India and its establishment provided practical proof of the viability of the independent regulatory commission model for the electricity sector.

Following the Orissa initiative, several other states undertook electricity sector reforms during the mid-to-late 1990s, including Haryana, Andhra Pradesh, Rajasthan, Uttar Pradesh, Gujarat, and Karnataka. These reforms varied considerably in scope and approach, but most included the establishment of State Electricity Regulatory Commissions (SERCs) and the functional separation of the vertically integrated SEB into distinct entities for generation, transmission, and distribution. The Central Government supported these state-level reforms through a programme of policy incentives and fiscal transfers linked to reform milestones, and through the enactment of the Electricity Regulatory Commissions Act, 1998, which provided the central statutory basis for the establishment of CERC and SERCs.

1.4 The Electricity Regulatory Commissions Act, 1998

The Electricity Regulatory Commissions Act, 1998 (hereinafter "the 1998 Act") was enacted as an interim measure to establish the Central Electricity Regulatory Commission (CERC) and to provide a legislative framework for the establishment of State Electricity Regulatory Commissions by state governments. The 1998 Act reflected the recognition that the reform of the electricity sector required an independent regulatory authority with statutory powers, rather than the ad hoc regulatory arrangements that had characterised the sector under the 1948 Act framework.

CERC was established under the 1998 Act in 1998 and immediately assumed jurisdiction over the determination of tariffs for central generating stations and the Inter-State Transmission System. The early years of CERC's operation demonstrated the workability of independent electricity regulation in India and generated the institutional experience and regulatory precedents that informed the design of the more comprehensive regulatory framework under the Electricity Act, 2003. CERC's early tariff orders, particularly those relating to the tariff of NTPC's generating stations and the ISTS charges of Powergrid Corporation, established important principles of cost-of-service regulation that continue to influence the tariff regulatory framework.

1.5 Expert Committee Reports and the Design of EA 2003

The design of the Electricity Act, 2003 was informed by an extensive process of expert deliberation, inter-ministerial consultation, and stakeholder engagement over several years. The Expert Group on Restructuring of SEBs produced a comprehensive report recommending fundamental restructuring through corporatisation and unbundling, independent regulatory commissions with statutory tariff-setting powers, open access in transmission and distribution, and the development of an electricity market framework. The Standing Committee on Power of the Planning Commission examined the development of the power sector and contributed to the policy framework that shaped the legislative drafting.

The Ministry of Power circulated successive draft versions of the proposed legislation through the late 1990s and early 2000s, inviting comment from state governments, industry bodies, consumer groups, legal experts, and technical professionals. The Parliamentary Standing Committee on Energy conducted hearings and received extensive written submissions on the draft Bill, and its recommendations on matters including the institutional structure of the regulatory commissions, the scope of open access, and the mechanisms for consumer protection substantially influenced the final legislative text. The Legislative Department of the Ministry of Law and Justice provided legal scrutiny of the draft, ensuring its constitutional soundness and legislative precision.

The Electricity Act, 2003 was passed by both Houses of Parliament and received Presidential assent on 26 May 2003, coming into force on 10 June 2003. The Act repealed and replaced the Indian Electricity Act, 1910; the Electricity (Supply) Act, 1948; and the Electricity Regulatory Commissions Act, 1998. The Statement of Objects and Reasons appended to the Bill set out the principal objectives of the legislation: to consolidate the laws relating to electricity; to promote competition; to protect consumer interests; to supply electricity to all areas; to rationalise tariff; to ensure transparent policies regarding subsidies; to promote efficient and environmentally benign policies; and to constitute the statutory bodies necessary for the governance of the reformed sector.

1.6 The Significance of EA 2003 as a Structural Reform Statute

The Electricity Act, 2003 is not merely a consolidating statute; it is a structural reform statute that fundamentally altered the legal architecture of the electricity sector. The shift from the State Electricity Board model of vertically integrated public monopoly to a framework of competitive generation, regulated transmission, and competitive distribution (through open access) represents a transformation in the legal theory of electricity governance — from the public law model of the developmental state to the regulatory state model that characterises the contemporary approach to infrastructure governance internationally.

Several features distinguish the EA 2003 as a structural reform statute. First, the de-licensing of generation removes the state's gatekeeping function in the entry of new generators, allowing market forces and regulatory signals to determine the composition of the generation fleet. Second, the mandatory open access provisions require regulated utilities to provide non-discriminatory access to their networks, creating the conditions for competitive supply to large consumers and preventing the abuse of network monopoly to foreclose competition in electricity supply. Third, the creation of independent regulatory commissions with broad statutory powers establishes an institutional buffer between the electricity utilities and the political process, reducing the scope for politically motivated interference in tariff determination and utility management.

At the same time, the EA 2003 preserves important elements of the public interest framework inherited from the 1948 Act. The statutory duty to supply electricity to all consumers in the area of supply (Section 43), the provisions for rural electrification (Section 5), the requirement that tariffs be just and reasonable (Section 61), and the framework for consumer protection and grievance redressal all reflect the continuing relevance of public service obligations in the governance of the electricity sector. The challenge for the regulatory framework established by the 2003 Act has been to reconcile these public interest obligations with the market-oriented reform agenda, a tension that continues to generate regulatory and judicial controversy.

Statute	Year	Key Institutional Features	Current Status
Indian Electricity Act	1910	Licensing framework; provincial oversight; technical standards; consumer protection basics; compulsory acquisition of private licensees after specified years	Repealed by EA 2003
Electricity (Supply) Act	1948	Central Electricity Authority; State Electricity Boards as vertically integrated monopolies; regional grid coordination; national electricity planning framework	Repealed by EA 2003
Atomic Energy Act	1962	Nuclear electricity generation; exclusive central authority; separate from EA 2003 framework; Department of Atomic Energy oversight	In force (separate from EA 2003)
Electricity Regulatory Commissions Act	1998	Central Electricity Regulatory Commission (CERC); framework for SERCs; interim tariff regulation for central sector; first independent regulatory commission	Repealed by EA 2003
Electricity Act	2003	Comprehensive reform framework; de-licensing of generation; mandatory open access; independent regulatory commissions; APTEL; competitive markets; consumer protection architecture	In force (as amended)

CHAPTER TWO

Constitutional Framework & Legislative Competence

Federalism, Concurrent Jurisdiction, Fundamental Rights, and the Power Sector

The Electricity Act, 2003 operates within a carefully constructed constitutional framework. The distribution of legislative competence between Parliament and the state legislatures, the principles governing the resolution of conflicts between central and state laws, and the fundamental rights guarantees of the Constitution all bear upon the interpretation and application of the electricity regulatory framework in significant ways.

2.1 Electricity in the Constitutional Scheme

The constitutional allocation of legislative and executive authority over electricity reflects the broader federal architecture of the Indian Constitution and the particular history of how electricity regulation evolved in the post-independence period. Electricity as a subject matter occupies Entry 38 of the Concurrent List (List III of the Seventh Schedule to the Constitution), which reads, simply and without elaboration: "Electricity." This placement vests concurrent authority over electricity in both Parliament and the state legislatures, making the electricity sector a classic domain of cooperative federalism in which the central and state governments must coordinate their legislative and executive activities to produce coherent and effective governance.

The placement of electricity in the Concurrent List, rather than in the Union List or the State List, reflects the dual character of electricity as a subject of governance. On the one hand, electricity generation and transmission involves large-scale infrastructure that spans multiple states, requires coordination at the national level, and has implications for national energy security and economic competitiveness. On the other hand, the distribution and retail supply of electricity is an intensely local activity that affects the daily lives of ordinary citizens, generates political pressure at the state level, and is closely connected to state-level development priorities and social policies including agricultural subsidies and rural electrification. The Concurrent List placement allows both the central and state governments to legislate on different aspects of the electricity sector according to their respective competences and priorities, subject to the overarching framework of the central legislation.

2.1.1 Entry 38, List III — Scope of Concurrent Competence

The Supreme Court of India has interpreted Entry 38 of the Concurrent List broadly and purposively, in accordance with its settled approach of reading the entries in the Seventh Schedule with the amplitude necessary to give full effect to the legislative power conferred by each entry. Entry 38 has been held to encompass: the regulation of the electricity industry in all its dimensions; the constitution of regulatory authorities and adjudicatory tribunals for the electricity sector; the determination of electricity tariffs and the principles and methodology of tariff regulation; the licensing of entities engaged in electricity generation, transmission, distribution, and trading; technical standards for the construction and operation of electrical installations and systems; the prevention and prosecution of offences relating to electricity including theft; and the establishment of frameworks for consumer protection and dispute resolution in the electricity sector.

This broad interpretation of Entry 38 has supported the constitutional validity of the comprehensive regulatory scheme established by the Electricity Act, 2003, including provisions that some states have argued encroach on their authority over subjects within the State List such as local government functions and public health. Courts have generally rejected such arguments on the basis that the challenged provisions fall squarely within the broad ambit of Entry 38 as a subject of concurrent legislative competence, and that Parliament's exercise of its concurrent legislative power through the comprehensive EA 2003 framework is a legitimate and constitutional exercise of central legislative authority.

2.1.2 Inter-State Rivers — Entry 56, List I

Entry 56 of the Union List vests Parliament with exclusive legislative competence over "regulation and development of inter-State rivers and river valleys to the extent to which such regulation and development under the control of the Union is declared by Parliament by law to be expedient in the public interest." This entry is directly relevant to the electricity sector because hydroelectric generation draws upon river waters, many of which flow through multiple states and are classified as inter-state rivers subject to central regulation. The practical consequence is that large hydroelectric projects on inter-state rivers — such as the Bhakra Nangal system on the Sutlej, the Rihand dam on the Rihand tributary of the Son, and the projects on the Beas and Ravi rivers — are governed by both the EA 2003 framework (with respect to electricity-related matters such as tariff, connectivity, and trading) and the central legislation and water allocation awards governing the distribution of river waters between the riparian states.

The Inter-State River Water Disputes Act, 1956, enacted under Entry 56 and Article 262 of the Constitution, establishes the framework for the constitution of tribunals to resolve disputes between states regarding the use and distribution of waters of inter-state rivers. The awards of these tribunals — including the Indus Waters Treaty (which governs certain rivers shared with Pakistan) and the awards of the Cauvery Water Disputes Tribunal, the Krishna Water Disputes Tribunals, and other river tribunals — directly affect the availability of water for hydroelectric generation and the allocation of the resulting electricity among the riparian states. Hydroelectric projects on inter-state rivers are thus subject to a complex multi-layered regulatory framework in which water law and electricity law intersect.

2.2 Article 254: Paramountcy of Parliamentary Law

Article 254 of the Constitution establishes the fundamental principle governing conflicts between Parliamentary law and state law on Concurrent List subjects. Article 254(1) provides that if any provision of a law made by the legislature of a state is repugnant to any provision of a law made by Parliament which Parliament is competent to enact, or to any provision of an existing law with respect to one of the matters enumerated in the Concurrent List, then the law made by Parliament or the existing law shall prevail and the state law shall, to the extent of the repugnancy, be void.

The principle of federal paramountcy under Article 254(1) is not absolute. Article 254(2) provides that where a law made by the legislature of a state is repugnant to any provision of an earlier law made by Parliament or an existing law with respect to a Concurrent List matter, the state law shall, if it has been reserved for the consideration of the President and has received the assent of the President, prevail in that state. This mechanism allows a state to legislate on a Concurrent List subject in a manner that is inconsistent with the central law, provided the state law receives Presidential assent. The Presidential assent requirement is a constitutional safeguard ensuring that the Central Government has the opportunity to review and, if necessary, withhold assent to state legislation that conflicts with central policy.

The interplay between Article 254(1) and Article 254(2) has generated significant litigation in the electricity sector. Several states have enacted state electricity legislation that departs in specific respects from the framework of the Electricity Act, 2003, relying on the Presidential assent mechanism to sustain the validity of the state law. Cases involving the interpretation of specific provisions of state electricity legislation and their consistency with the EA 2003 framework have been argued before regulatory commissions, APTEL, and the courts, generating a body of precedent on the principles governing the relationship between central and state electricity legislation.

Key Constitutional Provisions — Electricity Sector

Article 246: Distribution of legislative powers; the Seventh Schedule applies to determine the subject matter of Union and state legislative competence.

Article 254(1): Paramountcy of Parliamentary law over state law on Concurrent List subjects; state law void to the extent of repugnancy.

Article 254(2): State law may prevail over Parliamentary law on Concurrent List subject if state law receives Presidential assent; applicable in that state only.

Article 262: Adjudication of disputes relating to waters of inter-state rivers or river valleys; Parliament may exclude Supreme Court jurisdiction in such disputes.

Entry 38, List III: Electricity — concurrent legislative authority of Parliament and state legislatures.

Entry 56, List I: Regulation and development of inter-state rivers and river valleys — exclusive parliamentary competence.

Entry 52, List I: Industries controlled by the Union — may encompass large-scale power generation industries as declared by Parliament.

Entry 53, List I: Oil fields and mineral oil resources; petroleum and petroleum products — exclusive parliamentary competence; intersects with gas-based electricity generation.

2.3 Constitutional Validity of the Electricity Act, 2003

The constitutional validity of the Electricity Act, 2003 has been the subject of judicial scrutiny in several contexts. Constitutional challenges to specific provisions of the Act have been mounted on diverse grounds, including: alleged encroachment on the states' authority over subjects within the State List such as agriculture, local government, and public health; inconsistency with the constitutional scheme of fiscal federalism under Articles 268–293; violation of fundamental rights under Part III of the Constitution; and the alleged unconstitutional ouster of High Court jurisdiction through the creation of APTEL as the exclusive appellate forum for Commission orders.

2.3.1 Challenges to Open Access and Network Regulation Provisions

The provisions of the Electricity Act, 2003 mandating open access to transmission and distribution networks have been among the most contested on constitutional grounds. States and distribution utilities have argued that the mandatory open access provisions encroach on the states' authority over intra-state distribution of electricity, which they contend falls within the state's exclusive domain in practice if not in constitutional theory. The central response to these challenges has been that open access in transmission and distribution is an essential mechanism for promoting competition and protecting consumer interests in the electricity market, and therefore falls squarely within the scope of the broad Concurrent List competence over electricity.

Courts examining these challenges have generally upheld the constitutional validity of the open access provisions, holding that: the provisions of Sections 38, 39, 40, and 42 of the EA 2003 fall within Parliament's legislative competence under Entry 38 of the Concurrent List; the provisions represent a reasonable exercise of the power to regulate the electricity sector in the national interest; and the mandatory character of the open access obligations does not encroach on any protected sphere of state legislative authority since electricity is a concurrent subject over which Parliament may legislate comprehensively. The courts have also held that the provisions of the EA 2003 on open access, being later Parliamentary legislation, prevail over any inconsistent state legislation by virtue of Article 254(1).

2.3.2 The Jurisdiction of APTEL and the Article 226 Controversy

The creation of the Appellate Tribunal for Electricity (APTEL) as the exclusive appellate forum for orders of regulatory commissions has generated significant constitutional controversy regarding the continued availability of the High Courts' jurisdiction under Article 226 to review Commission orders. The High Courts possess constitutional jurisdiction under Article 226 to issue writs including mandamus, certiorari, and prohibition against any person or authority including the regulatory commissions, and this jurisdiction cannot be ousted by ordinary legislation without a constitutional amendment.

The legislative strategy adopted in the Electricity Act, 2003 does not purport to oust Article 226 jurisdiction; rather, Section 111 creates APTEL as an appellate forum, and Section 175 provides that civil courts and other courts shall not have jurisdiction in respect of any matter which the Commission or the Appellate Tribunal is empowered to determine. The Supreme Court has addressed the jurisdictional relationship between High Courts and APTEL in a number of decisions, holding that while High Courts retain their Article 226 jurisdiction in principle, the existence of an efficacious and specialised alternative remedy before APTEL is a strong reason for the High Courts to exercise restraint and decline to exercise their writ jurisdiction where APTEL provides an adequate and appropriate forum. The High Courts have generally followed this guidance, deferring to APTEL's jurisdiction in most cases involving challenges to Commission orders.

2.4 Fundamental Rights in the Electricity Sector

The intersection of the Part III fundamental rights guarantees of the Constitution with electricity sector regulation has generated a substantial and evolving body of jurisprudence. The principal constitutional provisions engaged include Article 14 (equality before law and equal protection of the laws), Article 19(1)(g) (right to carry on any occupation, trade, or business), Article 21 (right to life and personal liberty), and Article 31C (protection for laws implementing Directive Principles, which include the obligation of the state to ensure distribution of ownership and control of material resources of the community so as best to subserve the common good).

2.4.1 Article 14 — Equality and Non-Discrimination in Tariff Classification

The classification of electricity consumers into distinct categories for the purpose of tariff determination — domestic, agricultural, industrial, commercial, and so on — raises questions under Article 14 regarding the rationality and non-arbitrariness of consumer classification schemes. The Supreme Court and High Courts have consistently held that consumer classification schemes in electricity tariff orders are subject to Article 14 review, and that a classification of consumers must be based on intelligible differentia having a rational nexus with the object sought to be achieved. Courts have generally upheld the broad outlines of consumer classification schemes employed by regulatory commissions as resting on rational distinctions between different categories of consumers based on their nature of use, load factor, pattern of consumption, and ability to pay. However, courts have intervened in cases where specific sub-classifications within a consumer category have been found to be arbitrary or discriminatory.

2.4.2 Article 19(1)(g) — Right to Carry on Business in the Electricity Sector

The right to carry on any occupation, trade, or business under Article 19(1)(g), subject to reasonable restrictions in the interests of the general public under Article 19(6), has been frequently invoked in challenges to the licensing requirements, conditions, and restrictions imposed by the Electricity Act, 2003. Generating companies, distribution licensees, and trading licensees have at various times challenged the licensing framework, the conditions attached to licences, and the exercise of regulatory powers by the commissions as unreasonable restrictions on their fundamental right to carry on their business. Courts have generally held that the licensing framework and the exercise of regulatory powers by the commissions constitute reasonable restrictions on the right to carry on business in the electricity sector, justified by the strong public interest in the safe, reliable, affordable, and non-discriminatory supply of electricity to all sections of society.

2.4.3 Article 21 and the Right to Electricity

The question of whether the right to electricity supply is encompassed within the broad and evolving interpretation of the right to life under Article 21 has been addressed by several High Courts in the context of electricity disconnection cases, denial of connections, and inadequate supply to rural areas. While no authoritative Supreme Court decision has definitively established electricity supply as a constitutionally protected fundamental right, a body of High Court jurisprudence has developed the principle that: the arbitrary disconnection of electricity supply to a domestic consumer without following due process constitutes a violation of the right to life; the denial of an electricity connection to a rural household for which a legitimate application has been made may, in appropriate circumstances, violate the right to life if the denial prevents the household from accessing essential services; and the state's obligations under Article 21, read with the Directive Principles in Part IV of the Constitution, include the obligation to progressively improve the availability and quality of electricity supply to all sections of the population.

2.5 The States' Power to Regulate: Residual Competence and Constraints

While the Electricity Act, 2003 establishes a comprehensive central framework for electricity regulation, the states retain significant regulatory authority within the space left by the central legislation. States may enact legislation on concurrent electricity matters that supplements or elaborates the central framework, provided such state legislation is not inconsistent with the EA 2003 and does not require Presidential assent under Article 254(2) to sustain its validity. The boundary between permissible state supplementation and impermissible state inconsistency with the central framework is not always clear and has been the subject of litigation.

Examples of permissible state legislative action in the electricity sector include: the enactment of state electricity supply codes specifying detailed technical and commercial conditions for electricity connections; state legislation establishing the terms and conditions for the operation of franchisees within the licensed area of a distribution licensee; and state legislation providing for specific agricultural electricity supply programmes funded from the state budget. Examples of state action that may be inconsistent with the EA 2003 framework include: state legislation that purports to override Commission orders on tariffs or open access; state executive action that directs distribution utilities to deviate from open access obligations without Commission sanction; and state legislation that imposes additional barriers to entry in the generation or trading segments inconsistent with the de-licensing philosophy of the central Act.

Issue	Central Framework (EA 2003)	State Authority	Prevailing Legal Position
Open Access Charges	Charges must be non-discriminatory and cost-reflective; CERC regulates ISTS; SERC regulates intra-state	States claim authority to impose additional state-specific surcharges on open access consumers	Cross-subsidy surcharges permitted under Section 42; additional surcharge for stranded cost under Section 42(4); both subject to SERC determination and principles in Tariff Policy
Retail Tariff Subsidies	Tariff Policy requires rationalisation of cross-subsidies; subsidies to be transparent and time-bound	States claim absolute authority over tariff policy for domestic and agricultural consumers	SERC has final tariff-setting authority under Section 86; state government may subsidise consumers under Section 65 by direct payment to licensee
Distribution Privatisation	Act permits private distribution through licensing framework; does not mandate privatisation	States have authority over the ownership structure of distribution utilities	State government may choose to privatise distribution by permitting private licensing; cannot force SERC to grant licence or deny licence in violation of Commission's independent judgment
RPO Targets	Section 86(1)(e) mandates SERC to specify RPO; Tariff Policy provides national trajectory guidance	States contend authority to set state-specific RPO based on resource endowment	SERC specifies RPO within state; must have regard to national trajectory; Commission's independent judgment prevails

2.6 Energy Security and Constitutional Allocation of Resources

The constitutional framework for energy security encompasses a broader range of Seventh Schedule entries beyond Entry 38. Coal (Entry 54, List I), petroleum and natural gas (Entry 53, List I), and nuclear energy (Entries 52 and 6, List I) are within the exclusive domain of Parliament, creating a multi-layered framework in which the fuel supply chain for electricity generation is regulated independently of the electricity sector itself. This fragmentation of constitutional competence has practical implications for the coordination of energy policy across the coal, petroleum, power, and renewable energy ministries and their associated regulatory bodies.

The water resources dimension of electricity policy — through the hydroelectric generation nexus — brings in Entry 56 of the Union List (inter-state rivers) and Entry 17 of the State List (water, including water supplies, irrigation and canals, drainage and embankments, water storage, and water power). This creates a complex constitutional ecology in which the development of hydroelectric power involves the concurrent operation of at least three distinct heads of legislative competence: Entry 38 (electricity), Entry 56 (inter-state rivers), and Entry 17 (water power in intra-state context). The practical management of these overlapping jurisdictions requires inter-governmental coordination mechanisms and, when coordination fails, recourse to judicial adjudication.

CHAPTER THREE

Structure and Scheme of the Electricity Act, 2003

Legislative Architecture, Part-wise Analysis, and Core Statutory Provisions

The Electricity Act, 2003 is structured with meticulous legislative design, organising the comprehensive reform of India's electricity sector into a coherent statutory framework of ten Parts and 185 Sections. A thorough understanding of this legislative architecture is essential for practitioners who must navigate the Act's provisions in regulatory proceedings, commercial transactions, and dispute resolution.

3.1 Overview: Ten Parts and 185 Sections

The Electricity Act, 2003 is organised into ten Parts comprising 185 Sections, along with a Schedule to the Act. The Act's structure reflects a deliberate legislative design that separates the treatment of the electricity supply chain — generation, transmission, distribution, trading — from the institutional framework establishing the regulatory commissions and appellate tribunal, and from the administrative provisions governing offences, penalties, and miscellaneous matters. This structural separation facilitates the interpretation and application of specific provisions while maintaining the coherence of the overall legislative framework.

The ten Parts of the Act may be grouped functionally into three broad categories: first, framework provisions establishing national electricity policy and the regulatory philosophy of the Act (Parts I and II); second, sector-specific provisions governing the individual activities of generation, transmission, distribution, metering, and trading (Parts III, IV, IV-A, V, VI, and VII); and third, institutional provisions establishing the Central Electricity Authority, the Regulatory Commissions, and the Appellate Tribunal, together with the provisions governing their constitution, jurisdiction, powers, and procedures (Parts IV, VIII, and IX), supplemented by the enforcement provisions in Part X.

3.2 Part I — Preliminary (Sections 1–2): Definitions and Interpretive Framework

Part I of the Electricity Act, 2003, comprising Sections 1 and 2, contains the preliminary provisions establishing the short title, extent, commencement of different provisions, and definitions. Section 2, the definition section, contains 78 defined terms that collectively govern the interpretation of the entire Act. The definition section is one of the most extensively and carefully drafted provisions in the Act, reflecting the technical nature of the electricity sector, the importance of legal precision in a framework that creates binding obligations and enforceable rights, and the experience of interpretive disputes under predecessor legislation where the absence of clear statutory definitions had created uncertainty and litigation.

The 78 definitions in Section 2 cover: the principal actors and entities in the electricity sector (generating company, licensee, distribution licensee, transmission licensee, trading licensee, consumer, captive generating plant); the principal technical concepts of the electricity sector (power system, electrical line, overhead line, main transmission line, electric supply line, interconnection, grid); the institutional actors (Appropriate Commission, Appellate Tribunal, Central Authority, Central Government, State Government); the commercial concepts (open access, trading, wheeling, surcharge); and the procedural concepts (adjudicating officer, licence, prescribed). The precision and comprehensiveness of these definitions has significantly reduced (though not eliminated) interpretive uncertainty, and many of the definitions have been subject to extensive judicial and regulatory elaboration.

3.2.1 The Definition of "Appropriate Commission" — Section 2(4)

The definition of "Appropriate Commission" in Section 2(4) is foundational to the entire regulatory scheme of the Act, determining which regulatory commission — central or state — has jurisdiction over any given matter. Section 2(4) defines "Appropriate Commission" to mean: (a) the Central Electricity Regulatory Commission (CERC) in relation to matters affecting or likely to affect inter-state trade or commerce in electricity, or in relation to generating companies which the Central Government has declared to be of national importance; and (b) in all other cases, the State Commission (SERC) of the state in which the matter arises.

The inter-state trade or commerce test in Section 2(4)(a) is the key jurisdictional divide between CERC and the SERCs. The Supreme Court and APTEL have elaborated a jurisprudence of jurisdictional determination that applies this test to specific factual situations. The general principle is that CERC's jurisdiction is attracted wherever the matter "concerns or affects" inter-state trade or commerce in electricity, even if the physical facilities involved are located within a single state. This broad test has resulted in CERC's jurisdiction being upheld in a range of situations that might superficially appear to involve only intra-state activities, including: the tariff of a generating station that sells a portion of its output to distribution utilities in states other than the one in which it is located; open access transactions in which electricity crosses a state boundary at any point in the transmission path; and disputes relating to the allocation of ISTS transmission charges among generators with buyers in multiple states.

3.2.2 The Definition of "Open Access" — Section 2(47)

The definition of "open access" in Section 2(47) — "the non-discriminatory provision for the use of transmission lines or distribution system or associated facilities with such lines or system by any licensee or consumer or a person engaged in generation in accordance with the regulations specified by the Appropriate Commission" — is among the most practically significant definitional provisions in the Act. The three key elements of this definition merit individual analysis.

First, the requirement of "non-discriminatory" provision means that the licensee who owns and operates the transmission lines or distribution system cannot charge different rates or impose different conditions on different users of the system on grounds other than those that are objectively justified by the technical and commercial characteristics of the individual use. Discrimination between users is prohibited; differentiation based on rational and transparent criteria (such as the nature of the connection, the duration of the access arrangement, or the power factor of the consumer's installation) is permissible. The non-discrimination principle is central to the functioning of the competitive electricity market that the Act is designed to create: if network owners could discriminate among users, they could effectively prevent competition in electricity supply by imposing prohibitive conditions on competitors seeking to use their networks.

Second, the reference to "regulations specified by the Appropriate Commission" means that open access is not a self-executing right; it operates within a regulatory framework established by the relevant Commission. Both CERC (for the ISTS) and the SERCs (for the intra-state transmission system and distribution networks) have issued detailed open access regulations specifying the terms and conditions of open access, the charges payable, the procedures for applying for and receiving open access, and the mechanisms for dispute resolution.

3.2.3 Definition of "Consumer" — Section 2(15)

The definition of "consumer" in Section 2(15) as "any person who is supplied with electricity for his own use by a licensee or the Government or by any other person engaged in the business of supplying electricity to the public under the Act or such person whose premises are for the time being connected for the purpose of receiving electricity" is important for understanding the scope of consumer protection provisions in the Act. The definition is broad enough to encompass both metered consumers receiving electricity under a formal supply arrangement and persons whose premises are connected to the distribution network even without a formal supply contract. The breadth of the definition has implications for the determination of who is entitled to receive electricity supply under the Section 43 duty to supply, and who is entitled to access consumer protection mechanisms including the Consumer Grievance Redressal Forum and the Electricity Ombudsman.

3.3 Part II — National Electricity Policy and Plan (Sections 3–6)

Part II of the Act, comprising Sections 3 to 6, establishes the framework for national electricity planning and policy. This Part performs the important function of connecting the statutory regulatory framework to the broader policy framework within which the electricity sector operates, creating a legal mechanism through which national energy policy decisions can be translated into binding regulatory guidance.

3.3.1 Section 3 — National Electricity Policy and Tariff Policy

Section 3(1) mandates the Central Government to formulate the National Electricity Policy and Tariff Policy in consultation with the state governments and the Central Electricity Authority. The National Electricity Policy is required to be aimed at the development of the power system based on optimal utilisation of resources such as coal, natural gas, nuclear substances or materials, hydro and renewable sources of energy; promotion of efficient and environmentally benign policies; and competition, efficiency, and economy in activities of the electricity industry. Section 3(3) provides that the National Electricity Policy shall be published in the Official Gazette and thereafter reviewed and updated once in five years or earlier, as considered necessary by the Central Government in consultation with state governments and the Central Electricity Authority.

Section 3(4) requires the Central Electricity Authority to prepare a National Electricity Plan in accordance with the National Electricity Policy, and to revise the Plan once in five years. The National Electricity Plan (NEP) is a statutory planning document of great operational significance: it provides the authoritative assessment of expected demand growth, the requirement for capacity addition across different generation technologies including renewable energy, the investment needed in the Inter-State Transmission System, the fuel requirements for the planned generation capacity, and the financial resource requirements. The NEP serves as the primary reference document for investment planning by generating companies, transmission developers, fuel suppliers, and financial institutions.

Section 3(6) provides that the Appropriate Commission shall take the National Electricity Policy and National Electricity Plan into account in performing its functions. This provision establishes the legal nexus between the national planning documents and the regulatory decisions of CERC and the SERCs, ensuring that tariff determinations, licensing decisions, and other regulatory actions are consistent with the national electricity plan. The practical application of this provision is elaborated through specific provisions in the CERC and SERC regulations that require applicants for tariff determination or licensing to demonstrate consistency with the National Electricity Plan and the applicable state plans.

3.3.2 The Tariff Policy: Legal Status and Content

The Tariff Policy, notified by the Central Government under Section 3(1), has a distinctive legal character: it is not a statute, but it is binding on the regulatory commissions and therefore has legal effect beyond that of an ordinary executive policy document. Section 61 of the Act, which prescribes the principles and guidelines within which the Appropriate Commission shall determine tariffs, cross-references the Tariff Policy by requiring the Commission to have regard to the Tariff Policy when determining tariffs.

The Tariff Policy of 2016 — the most recent comprehensive revision of this document as of the date of this publication — addresses a wide range of matters including: the principles of cost recovery and tariff determination for regulated utilities; the framework for competitive procurement of electricity through bidding; the rationalisation of cross-subsidies in electricity tariffs; the provisions for payment of subsidies through direct transfer to consumers rather than through cross-subsidisation; the Renewable Purchase Obligation and Renewable Energy Certificate framework; the norms for fuel cost pass-through in tariff determination; and the provisions for the treatment of coal blocks, gas fields, and other captive fuel sources in tariff determination. Each of these matters is elaborated in detail in the Tariff Policy and provides guidance to regulatory commissions in the exercise of their tariff-setting functions.

3.4 Part III — Generation of Electricity (Sections 7–12): De-licensing and Regulatory Conditions

Part III of the Act establishes the legal regime for electricity generation, the most commercially significant departure of the EA 2003 from the predecessor legislative framework. The fundamental innovation of Part III is the removal of the licensing requirement for electricity generation — a reform that has directly enabled the massive expansion of private sector participation in electricity generation that has transformed the Indian electricity sector over the two decades since the Act's enactment.

3.4.1 Section 7 — De-licensing of Generation

Section 7 of the Electricity Act, 2003 provides that any generating company may establish, operate, and maintain a generating station without obtaining a licence under the Act, if it complies with the technical standards relating to connectivity with the grid referred to in clause (b) of Section 73. The significance of this provision can hardly be overstated: it converts electricity generation from a licensed monopoly activity (as it was under the 1948 Act framework) into a freely permitted economic activity subject only to technical standards and connectivity requirements. Any company, partnership, association, or individual may establish and operate a generating station without seeking prior approval from any regulatory authority, subject only to the requirement of satisfying the CEA's technical standards for connectivity to the grid.

The de-licensing of generation has two principal practical consequences. First, it eliminates the regulatory barrier to entry that previously required prospective generators to obtain Commission approval before investing in generation capacity. This has dramatically reduced the time required to move from investment decision to generation development (though regulatory approvals for environmental clearances, land acquisition, fuel linkages, and power purchase agreements continue to be required under other legal frameworks). Second, it creates the conditions for competitive supply of electricity to the market: in the absence of entry restrictions, multiple generators can compete to supply electricity to distribution utilities, open access consumers, and other buyers, driving down prices through competitive pressure.

3.4.2 Sections 10–11 — Grid Connectivity and Emergency Powers

Section 10 of the Electricity Act, 2003 imposes a duty on every generating company to operate and maintain its generating station, including the generating equipment, transformer, switch gear, and associated apparatus, in accordance with the technical standards relating to connectivity with the grid specified under Section 73(b) of the Act. This provision ensures that while the decision to establish a generating station is free from regulatory licensing requirements, the operation of the station must comply with technical standards that protect the safety and reliability of the electricity grid as a whole.

Section 11 is an important provision that qualifies the general framework of liberalised generation by vesting the Central Government and state governments with the power to give directions to any generating company in situations of emergency. Section 11(1) provides that the Central Government may, in a situation of adversely affecting the maintenance of supplies of electricity to any area, give directions to any generating company to give priority to the supply of electricity to any area or to operate any generating station at any reduced or increased load. This power enables the Government to intervene in the operation of private generating stations in situations of national energy emergency, ensuring that de-licensing of generation does not prevent the Government from managing crisis situations in the electricity sector.

3.5 Parts IV-A — Transmission of Electricity (Sections 26–41)

The transmission provisions in Sections 26–41 establish the legal architecture for the Inter-State Transmission System and for intra-state transmission systems. The regulatory treatment of transmission reflects the natural monopoly characteristics of transmission infrastructure: unlike generation, where multiple competitors can serve the same market, transmission networks exhibit economies of scale that make parallel infrastructure economically irrational. The legal framework therefore regulates transmission as a natural monopoly activity, imposing non-discriminatory access obligations and cost-based tariff regulation on transmission licensees.

3.5.1 Section 38 — Duties of the Central Transmission Utility

Section 38 of the Electricity Act, 2003 is the principal provision governing the Central Transmission Utility (CTU), which is currently designated as Powergrid Corporation of India Limited (PGCIL). Section 38(1) provides that it shall be the duty of the Central Transmission Utility to build, maintain, and operate an efficient, co-ordinated, and economical inter-State transmission system; to provide non-discriminatory open access to its transmission system for use by any licensee or generating company or any consumer, in accordance with regulations made by the Central Commission; and to discharge all functions of planning and co-ordination relating to inter-State transmission systems with the State Transmission Utilities, Central Government, State Governments, generating companies, regional electricity boards, and other authorities.

The non-discriminatory open access obligation in Section 38(1)(b) is the legal foundation of the open access framework for the Inter-State Transmission System. The CTU cannot refuse access to its transmission network to any eligible user who satisfies the applicable connectivity and access conditions specified in CERC's regulations, nor can it charge different prices or impose different conditions on different users on grounds other than those permitted by the regulations. This obligation transforms the CTU from a monopoly provider serving only the utilities with which it has direct contractual relationships into a common carrier for the electricity market, facilitating transactions between generators and buyers who would otherwise have no legal right to use the CTU's network.

3.6 Part V — Distribution of Electricity (Sections 42–64)

Part V of the Act, comprising Sections 42 to 64, is the part of the Act with the most direct impact on the day-to-day lives of ordinary electricity consumers. These provisions govern the distribution of electricity from the distribution network to consumers, the obligations of distribution licensees to supply electricity, the framework for open access to the distribution system, the determination of tariffs for supply to consumers, and the mechanisms for consumer protection and dispute resolution.

3.6.1 Section 43 — Duty to Supply

Section 43 of the Electricity Act, 2003 provides that it shall be the duty of every distribution licensee to supply electricity on an application being made to him by the owner or occupier of any premises in his area of supply. This duty to supply is a statutory obligation enforceable against the distribution licensee, and its breach creates a right of action in the aggrieved consumer. The duty to supply is conditioned on the payment of applicable charges including security deposits, connection charges, and any applicable tariff, and on compliance with reasonable technical conditions relating to the nature and capacity of the connection requested. However, the licensee cannot refuse to supply electricity on any other ground without specific statutory authority.

3.6.2 Section 42 — Duty of Distribution Licensee as Common Carrier

Section 42 of the Electricity Act, 2003, dealing with the duty of distribution licensees in relation to open access, is one of the most commercially significant provisions in the Act. Section 42(2) provides that every distribution licensee shall provide open access to any person who requires such access for the purposes of carrying electricity from a generating company or licensee to any premises, subject to availability of adequate infrastructure and payment of charges determined by the SERC. This provision enables large consumers who can source electricity competitively from generators or traders to use the distribution licensee's network to deliver that electricity to their premises, without having to purchase electricity exclusively from the distribution licensee as the monopoly supplier.

Section 42(4) enables the State Commission to specify a cross-subsidy surcharge to be charged on persons availing open access. Section 42(6) requires every distribution licensee to establish a forum for redressal of grievances of consumers. Together, these provisions create a comprehensive framework for the regulation of distribution licensee activities in relation to both their captive consumers and open access users, balancing the interests of large consumers seeking competitive supply with the interests of the utility and its captive consumers who contribute to cross-subsidisation.

3.6.3 Sections 62–63 — Tariff Determination: Two Pathways

The Act creates two distinct pathways for the determination of electricity tariffs. Section 62 provides the traditional regulatory pathway: the Appropriate Commission determines the tariff for generation, supply, transmission, and wheeling of electricity, and such determination is made through a formal regulatory proceeding in which the utility files a tariff petition and the Commission adjudicates the tariff based on the costs incurred by the utility and the principles specified in Section 61. Section 63 provides an alternative pathway: where electricity is procured by a distribution licensee or any other person through a process of competitive bidding conforming to the guidelines issued by the Central Government, the Appropriate Commission shall adopt the tariff discovered through competitive bidding without further scrutiny of the underlying costs.

The co-existence of these two tariff determination pathways reflects the transitional character of the current period in the Indian electricity market. The Section 62 pathway is appropriate for existing regulated utilities and for new investments by regulated entities (particularly central public sector undertakings) that are developing regulated assets on a cost-of-service basis. The Section 63 pathway is appropriate for new capacity procured through competitive processes, where the efficiency of competitive markets can be relied upon to discipline costs and generate value for consumers. Over time, as the competitive market matures and expands, the Section 63 pathway has become the dominant mechanism for new capacity procurement, with the Section 62 pathway increasingly confined to regulated transmission assets and legacy generation capacity.

Part	Sections	Subject Matter	Key Provisions
Part I	1–2	Preliminary	Short title; commencement; 78 statutory definitions covering entities, concepts, institutions
Part II	3–6	National Electricity Policy & Plan	NEP; Tariff Policy; stand-alone rural systems; rural electrification; CEA directions
Part III	7–12	Generation of Electricity	De-licensing of generation; technical standards compliance; emergency powers; Section 12 licensing threshold
Part IV	13–25	Central Electricity Authority	Constitution; qualifications; Section 73 functions; advisory role; grid and technical standards
Part IV-A	26–41	Transmission of Electricity	CTU designation; STU designation; transmission licensing; Section 38 CTU duties; ISTS open access
Part V	42–64	Distribution of Electricity	Section 43 duty to supply; Section 42 open access; consumer protection; CGRF; Sections 62–63 tariff determination
Part VI	65–74	Trading in Electricity	Trading licence requirement; categories of trading licences; code of conduct for traders
Part VII	75–83	Metering	Obligation to install meters for all supply; meter reading standards; Smart meter provisions
Part VIII	84–114	Regulatory Commissions	CERC constitution (Sections 76–78); SERC constitution (Sections 82–90); JERC (Section 83); functions; tariff powers; advisory; disputes
Part IX	110–125	Appellate Tribunal for Electricity	APTEL constitution; composition; Section 111 jurisdiction; powers; procedure; Section 125 Supreme Court appeal
Part X	126–185	Miscellaneous	Works; land; offences; electricity theft (Section 135); penalties; assessment (Section 126); transitional provisions

CHAPTER FOUR

Central Electricity Authority

Constitution, Functions, Technical Mandate, and Regulatory Interface

The Central Electricity Authority occupies a unique and indispensable position in the electricity governance architecture of India. As the premier technical advisory body for the electricity sector, it bridges the gap between scientific and engineering expertise on one hand and regulatory and policy decision-making on the other, providing the authoritative technical foundation upon which regulatory and planning decisions are built.

4.1 Historical Origins and Constitutional Lineage

The Central Electricity Authority has a long institutional lineage that predates the Electricity Act, 2003. The CEA was originally established under the Electricity (Supply) Act, 1948, which vested it with comprehensive functions relating to the development of the national electricity supply system. For more than five decades, the CEA served as both the apex technical body for planning and coordination of the electricity sector and, in the absence of independent regulatory commissions, as the primary authority for technical regulation of generating stations and transmission systems owned by the central government.

The creation of the Central Electricity Regulatory Commission (CERC) under the Electricity Regulatory Commissions Act, 1998, and subsequently under the Electricity Act, 2003, fundamentally altered the institutional architecture within which the CEA operates. With the establishment of CERC as an independent body with statutory authority to determine tariffs, issue licences, and adjudicate disputes, the CEA was freed from the quasi-regulatory functions it had performed by default in the absence of an independent regulator and could focus on its core technical advisory, planning, and standards-setting functions. The Electricity Act, 2003 reconstitutes the CEA under its provisions and specifies its functions comprehensively in Section 73, providing the statutory basis for the CEA's contemporary role in electricity sector governance.

4.2 Constitution and Composition of the CEA

The Central Electricity Authority is constituted by the Central Government by notification in the Official Gazette, with such number of members, including a Chairperson and a Member (Technical), as the Central Government may think fit to appoint. The Central Government is not bound to a specific number of members and retains flexibility to constitute the CEA with a membership appropriate to the evolving technical responsibilities of the Authority. In practice, the CEA has been constituted with a Chairperson and several Members, each of whom heads a distinct technical or functional division of the Authority corresponding to the major areas of CEA's mandate.

The qualifications for appointment as a member of the CEA are not specified in the same level of detail as those for the regulatory commissions. However, the nature of the CEA's functions — which encompass technical standards, system planning, hydrology, power economics, and data analysis — means that members are typically appointed from among senior government officials and public sector technical professionals with long experience in the electricity sector. The Chairperson of the CEA is typically a person with broad experience in electricity sector governance, while the Members are specialists in areas including generation technology, transmission systems, hydrology and hydroelectric projects, and power economics.

4.3 Functions of the CEA — Section 73 in Detail

Section 73 of the Electricity Act, 2003 specifies the functions of the Central Electricity Authority in eighteen separate clauses (Section

73(a) through Section 73(r)). These functions collectively position the CEA as the authoritative technical body for the Indian electricity sector, providing the technical underpinning for regulatory decisions, investment planning, and policy formulation across the sector. An analysis of the principal functions follows.

4.3.1 National Electricity Plan — Sections 73(a) and 3(4)

The CEA's most strategically significant function is the preparation of the National Electricity Plan (NEP) in accordance with the National Electricity Policy, under Section 73(a) read with Section 3(4) of the Act. The NEP is prepared by the CEA in consultation with the state governments, power utilities, the regulatory commissions, and other stakeholders, and is approved by the Ministry of Power before publication. The plan covers a five-year perspective period and is updated every two years to reflect new information about demand trends, generation additions, fuel supply developments, and policy priorities.

The NEP performs several important functions in the electricity governance system. For investors and developers, it signals the Government's assessment of the requirement for capacity addition in different generation technologies, providing a market signal that informs investment decisions in generation and fuel supply infrastructure. For transmission planners, it provides the generation addition data necessary for long-term transmission planning, enabling the CTU and STUs to develop transmission capacity consistent with projected generation additions. For regulatory commissions, it provides the contextual information necessary for assessing applications for long-term transmission access and for evaluating the consistency of new generation projects with the national electricity system's needs. For state governments and distribution utilities, it provides reference data for procurement planning and resource adequacy assessment.

4.3.2 Technical Standards for Electrical Plant and Lines — Section 73(b)

Section 73(b) vests the CEA with the function of specifying technical standards for the construction of electrical plants, electric lines, and connectivity with the grid. The CEA discharges this function through the issuance of technical standards documents that cover a wide range of subjects including: the technical standards for construction of electrical plants and electric lines (addressing the design, materials, equipment specifications, and construction practices for major categories of generation and transmission assets); the Indian Electricity Rules, which specify detailed technical and safety requirements for electrical installations; the technical standards for connectivity of generating stations, ESS (Energy Storage Systems), and renewable energy generating units to the grid; and technical standards for metering and data communication in the context of the smart grid rollout.

The technical standards issued by the CEA are binding on all parties engaged in the construction, operation, and maintenance of electrical plants and lines connected to the electricity grid. Generating companies developing new projects must design and construct their generating stations in accordance with the CEA's technical standards for connectivity, as a condition of being entitled to connect to the grid. Transmission licensees constructing new transmission lines and substations must comply with the applicable CEA technical standards for construction. Distribution licensees must ensure that their distribution systems and the consumer installations connected to them comply with the applicable Indian Electricity Rules and related standards. Non-compliance with CEA technical standards is a technical offence under the Act and exposes the defaulting party to regulatory and penal consequences.

4.3.3 Grid Standards — Section 73(c) and the Indian Electricity Grid Code

Section 73(c) vests the CEA with the function of specifying grid standards for the operation and maintenance of transmission lines. Grid standards address the dynamic aspects of power system operation — the parameters of frequency, voltage, and reactive power that must be maintained within specified limits for the electricity grid to operate safely and reliably. The CEA's grid standards are the technical foundation upon which the Indian Electricity Grid Code (IEGC), issued by CERC under Sections 73(c) and 79(1)(h) of the Act, is constructed.

The IEGC specifies, in operational detail, the requirements that generators, transmission licensees, distribution licensees, and large consumers must comply with when connected to and operating within the inter-state electricity grid. The key areas covered by the IEGC include: the operational frequency standards for the Indian grid (currently a nominal 50 Hz with prescribed tolerance bands); the voltage standards at different voltage levels of the transmission system; the reactive power obligations of generators and transmission licensees; the scheduling and despatch procedures through which generators submit generation schedules and receive despatch instructions from the Regional Load Despatch Centres; the energy accounting and settlement procedures through which the actual generation and consumption of each entity connected to the grid is measured, recorded, and reconciled with the scheduled quantities; and the procedures for handling emergency situations including grid disturbances, equipment failures, and frequency excursions beyond normal operating bands.

4.3.4 Data Collection, Analysis, and Publication — Sections 73(d) and (e)

Sections 73(d) and 73(e) vest the CEA with functions relating to the collection, recording, and publication of data concerning the generation, transmission, distribution, and utilisation of electricity in India. These functions are not merely administrative; they constitute the information infrastructure of the electricity sector, providing the authoritative data upon which regulatory decisions, investment planning, and policy analysis depend.

The CEA discharges its data functions through an extensive programme of data collection from electricity utilities, generators, transmission companies, and distribution licensees. The data collected covers: installed generation capacity by type of generation, by state, by ownership (central, state, private), and by unit; monthly and annual generation statistics including net generation, gross generation, auxiliary consumption, and generation by fuel type; plant availability and plant load factors for individual generating units and categories of generation; transmission network parameters including line lengths, substation capacities, and transformation capacities at different voltage levels; distribution loss percentages for individual distribution utilities; peak demand and energy consumption data by state and by consumer category; and financial performance data for electricity utilities including revenue, expenditure, outstanding dues, and AT&C loss statistics.

The CEA publishes its collected data through several authoritative annual publications including: "Growth of Electricity Sector in India from 1947"; "General Review"; "Report on Load Generation Balance"; "Annual Report on the Working of State Power Utilities and Electricity Departments"; and "Installed Capacity Report." These publications are the primary source of electricity sector statistics for researchers, investors, policymakers, and regulatory practitioners. The authoritative character of CEA data is reflected in the practice of regulatory commissions, APTEL, and courts citing CEA publications as the reference source for sector statistics.

4.3.5 Hydro-Electric Development Advisory — Section 73(f)

Section 73(f) vests the CEA with the function of advising the Central Government on matters relating to hydro-electric development, including the survey and investigation of river basin potentials, the preparation of perspective plans for hydro-electric development, the preparation of detailed project reports for individual projects, and the review of hydrological and engineering studies submitted by developers. Hydroelectric power is the only renewable energy technology that provides both energy and capacity on a dispatchable basis, and its development is strategically important for the electricity system as renewable generation from variable sources such as solar and wind expands. The CEA's advisory role in hydro-electric development positions it as the technical gatekeeper for this strategically significant segment of the generation mix.

The CEA's most consequential function in the hydro-electric segment is the grant of techno-economic concurrence to major hydroelectric projects. Under established administrative practice, major hydroelectric projects require CEA concurrence before the developer can commit significant financial resources to the project or seek regulatory approvals for power purchase agreements and tariff determination. The techno-economic concurrence process involves the CEA's review of: the feasibility study and detailed project report for the proposed project; the hydrological analysis supporting the proposed installed capacity and energy generation estimates; the structural design of the dam, powerhouse, and associated civil works; the electrical and mechanical equipment specifications; the cost estimate and financial analysis; and the environmental and social impact assessment. CEA concurrence is a signal of technical credibility that facilitates the developer's ability to secure financing, power purchase agreements, and regulatory approvals.

4.3.6 Promotion of Research, Design, and Development — Section 73(i)

Section 73(i) vests the CEA with the function of promoting research, design, and manufacture activities in relation to electricity in the country, including the identification of areas where such promotion is required in the national interest. In exercise of this function, the CEA coordinates with research institutions such as the Central Power Research Institute (CPRI), the National Institute of Technology, and the Indian Institutes of Technology, as well as with the manufacturing industry, to identify technological gaps and promote indigenous development of electricity sector equipment and technology. The CEA's research promotion function has taken on increased importance in the context of the energy transition, as India develops new technologies and manufacturing capabilities for renewable energy equipment, storage systems, and smart grid infrastructure.

4.4 CEA and the Regulatory Commissions: A Critical Distinction

Perhaps the most important structural feature of the CEA's institutional role is its clear distinction from the regulatory commissions — CERC and the SERCs — in terms of functions, powers, and mode of operation. The CEA is an advisory and technical body; the regulatory commissions are quasi-judicial regulatory bodies. The CEA advises and specifies technical standards; the regulatory commissions adjudicate, determine tariffs, and grant licences. The CEA does not hear and decide disputes between parties; the regulatory commissions do. The CEA does not determine the financial entitlements of any party; the regulatory commissions do. This functional distinction is reflected in the different compositions of the two types of bodies: the CEA is composed of technical experts, while the regulatory commissions are required to have judicial and economic expertise alongside technical expertise.

CEA Function	Statutory Basis	Key Output or Instrument	Practical Significance
National Electricity Plan	Section 73(a) / Section 3(4)	National Electricity Plan (biennial publication)	Capacity planning reference; transmission planning basis; policy guidance
Technical Standards	Section 73(b)	Technical Standards for Construction of Electrical Plants and Lines; Indian Electricity Rules	Binding construction and safety requirements for all electricity infrastructure
Grid Standards	Section 73(c)	Indian Electricity Grid Code (via CERC); frequency and voltage norms	Operational standards for real-time grid operation and system reliability
Data and Statistics	Section 73(d), (e)	Annual publications; sector performance data; load generation balance reports	Authoritative sector data; regulatory and investment reference
Hydroelectric Advisory	Section 73(f)	Techno-economic concurrence for hydroelectric projects; basin studies	Technical gatekeeper for hydro development; credibility signal for financing
Research Promotion	Section 73(i)	Coordination with research institutions; identification of technology gaps	Support for indigenous technology development and manufacturing
Heat Rate Norms	Section 73(j)	Normative operating parameters for generating stations	Efficiency benchmarks used in cost-based tariff determination by CERC/SERCs
Load Forecasting	Section 73(k)	Regional and national load forecasts; energy balance assessments	System planning data for transmission and generation investment decisions

CHAPTER FIVE

Central Electricity Regulatory Commission

Jurisdiction, Powers, Tariff Authority, Regulatory Instruments, and Jurisprudence

The Central Electricity Regulatory Commission (CERC) is the apex economic regulatory authority for the inter-state electricity sector in India. Since its establishment in 1998 (under the Electricity Regulatory Commissions Act) and reconstitution under the Electricity Act, 2003, CERC has developed a comprehensive body of regulatory jurisprudence that shapes the commercial and operational landscape of the Indian electricity market.

5.1 Constitution and Structural Independence of CERC

The Central Electricity Regulatory Commission is constituted under Sections 76–78 of the Electricity Act, 2003. CERC is headed by a Chairperson who has been or is qualified to be appointed as a Judge of the Supreme Court of India. This requirement ensures that the Commission's proceedings are conducted with the procedural rigour of a judicial forum and that its decisions carry the authority of a quasi-judicial body at the highest level. The four other Members of CERC must each be a person having adequate knowledge of, and experience or capacity in, dealing with problems relating to engineering, finance, commerce, economics, law, or management. This broad specification of relevant expertise reflects the multi-disciplinary nature of electricity regulation and allows the Commission to bring to bear diverse professional perspectives on the technical, economic, financial, and legal dimensions of electricity regulatory issues.

The provisions of the Electricity Act, 2003 relating to the tenure, remuneration, and post-retirement employment restrictions applicable to CERC's Chairperson and Members are designed to ensure the structural independence of the Commission from governmental and commercial interests. Section 91 provides that the Chairperson and every Member of CERC shall hold office for a term of five years from the date of entering upon office and shall be eligible for re-appointment. The age limit for the Chairperson is 70 years, and for Members is 65 years. Section 94 imposes restrictions on the post-retirement employment of ex-CERC members, prohibiting them from accepting employment with any company in the electricity sector for a period of two years after leaving the Commission. These restrictions are intended to prevent conflicts of interest and maintain the integrity of the regulatory process by ensuring that regulatory decisions are not influenced by the prospect of future commercial employment in the regulated sector.

The financial independence of CERC is protected by Section 97, which provides that the salaries, allowances, and other conditions of service of the Chairperson and Members of CERC shall be such as may be prescribed by the Central Government, and these shall not be varied to their disadvantage after their appointment. Section 99 provides for the funds of CERC to be credited to the Consolidated Fund of India, and Section 100 provides for the grants to CERC from the Consolidated Fund for meeting its expenditure. This financial dependence on the Consolidated Fund rather than on licence fees or levies collected from regulated entities is designed to prevent the perception of financial conflicts of interest in CERC's regulatory decisions.

5.2 Jurisdiction and Functions of CERC — Section 79

Section 79 of the Electricity Act, 2003 specifies the functions of the Central Commission in detailed enumeration. These functions represent the full scope of CERC's regulatory mandate and may be categorised into four principal areas: tariff regulatory functions; licensing functions; open access and market regulatory functions; and advisory functions.

5.2.1 Tariff Regulatory Functions — Sections 79(1)(a) and (b)

The tariff regulatory function is the most commercially significant of CERC's functions and the one that generates the greatest volume of regulatory proceedings before the Commission. Section 79(1)(a) vests CERC with the function of "regulating the tariff of generating companies owned or controlled by the Central Government." This provision gives CERC jurisdiction over the tariff of the major central public sector generating companies including NTPC Limited (National Thermal Power Corporation), NLC India Limited (National Lignite Corporation), and the Nuclear Power Corporation of India Limited (NPCIL), as well as any other central government-owned generating entity.

Section 79(1)(b) vests CERC with the function of "regulating the tariff of generating companies, other than those owned or controlled by the Central Government, if such generating companies enter into or otherwise have a composite scheme for generation and sale of electricity in more than one State." This provision extends CERC's tariff jurisdiction beyond central government generating companies to private and state government generating companies that have multi-state power purchase arrangements. The practical significance of Section 79(1)(b) is considerable in the context of large-scale renewable energy projects developed under central government programmes (such as the Solar Energy Corporation of India's procurement programmes) where the electricity is sold to distribution utilities in multiple states: such projects attract CERC's tariff jurisdiction even though the developer may be a private company and the project may be physically located in a single state.

Section 79(1)(c) extends CERC's tariff jurisdiction to "the tariff for transmission of electricity, wheeling charges in respect of inter-state operations." This provision is the basis for CERC's determination of the transmission tariff for the Inter-State Transmission System, the charges for the use of which are paid by the generators, distribution utilities, and open access consumers who use the ISTS to move electricity from generating stations to load centres across state boundaries. The determination of ISTS transmission charges is technically complex, involving the allocation of transmission costs among a large number of injection and withdrawal points across the national grid, and has been the subject of detailed regulatory deliberation by CERC resulting in successive regulatory frameworks for the sharing of transmission charges and losses.

5.2.2 Licensing Functions — Section 79(1)(c)

CERC exercises licensing functions in relation to trading in electricity on an inter-state basis. The trading licence framework established by CERC categorises trading licensees into two categories based on their trading volume and financial capacity. An "unrestricted category" trading licence permits the holder to trade in electricity without any ceiling on trading volume, and requires the licensee to satisfy minimum net worth and other financial requirements prescribed by CERC. A "restricted category" trading licence imposes a ceiling on the volume of electricity that the licensee may trade in any year, and has lower minimum financial requirements. CERC monitors the compliance of trading licensees with their licence conditions through periodic reporting requirements and field inspections, and has the power to modify, suspend, or revoke a trading licence for non-compliance.

5.2.3 Open Access and Market Regulatory Functions — Sections 79(1)(d) and (e)

Sections 79(1)(d) and (e) vest CERC with the functions of "regulating power systems in matters including regulation of inter-State transmission of electricity" and "specifying Grid Code having regard to Grid Standards specified under clause (c) of section 73." In exercise of these functions, CERC has developed a comprehensive regulatory framework for the operation of the Inter-State Transmission System and the organised electricity markets in India.

The open access regulatory framework for the ISTS, developed by CERC through successive iterations of its Open Access Regulations, provides for three categories of access to the ISTS: Long-Term Access (LTA) for a period of twenty-five years, which provides the generator or buyer with a firm right to transmission capacity on the ISTS; Medium-Term Open Access (MTOA) for a period of three months to three years; and Short-Term Open Access (STOA) for periods up to one month. The CERC (Grant of Connectivity and General Network Access) Regulations, 2022, introduced significant changes to the ISTS access framework, replacing the project-specific Long-Term Access model with a flexible General Network Access (GNA) framework that allows renewable energy generators to access the ISTS without securing dedicated transmission corridor rights, facilitating more efficient use of the shared transmission network.

Section 61 of EA 2003 — Guiding Principles for Tariff Determination

> The Appropriate Commission shall determine the tariff in accordance with the provisions of the Act, and in doing so it shall be guided by the following, namely: (a) the principles and methodologies specified by the Central Commission for determination of the tariff applicable to generating companies and transmission licensees; (b) the generation, transmission, distribution, and supply of electricity are conducted on commercial principles; (c) the factors which would encourage competition, efficiency, economical use of the resources, good performance, and optimum investments; (d) safeguarding the interests of the consumers and at the same time recovery of the cost of electricity in a reasonable manner; (e) the principles rewarding efficiency in performance; (f) multi-year tariff principles; (g) that the tariff progressively reflects the cost of supply of electricity and also, reduces and eventually eliminates cross-subsidies within the period to be specified by the Appropriate Commission; (h) the promotion of co-generation and generation of electricity from renewable sources of energy; (i) the National Electricity Policy and Tariff Policy.

5.3 CERC Regulatory Instruments: Regulations, Orders, and Directions

CERC exercises its regulatory functions through three principal types of instruments: regulations, orders, and directions. Regulations are legislative in character and are made by CERC in exercise of its regulation-making power under Section 178 of the Act, subject to prior publication in draft form for public comment and approval by the Central Government in accordance with the Act's provisions. Regulations are general in application, binding on all persons and entities within CERC's jurisdiction on the subject matter covered by the regulation. Major CERC regulations include the Terms and Conditions of Tariff Regulations (governing cost-based tariff determination), the Open Access Regulations (governing access to the ISTS), the Power Market Regulations (governing the Power Exchanges and organised electricity markets), and the Conduct of Business Regulations (governing CERC's own proceedings).

Orders are adjudicatory determinations made by CERC in specific proceedings before it, such as tariff petitions, licensing applications, and dispute petitions. Orders are binding on the parties to the proceeding and may also have precedential value for similar proceedings. A tariff order for a specific generating station determines the tariff payable by the procurer(s) for electricity from that station; a licensing order grants or modifies the licence of a specific trading licensee; a dispute order resolves the specific dispute between named parties. Orders of CERC are subject to appeal before APTEL under Section 111 of the Act. Directions are communications issued by CERC to licensees or generators in the exercise of the Commission's supervisory and compliance oversight functions; they are typically issued in response to non-compliance with licence conditions or regulatory requirements, and direct the recipient to take specific corrective action.

5.3.1 Major CERC Regulations — Reference Framework

CERC Regulation	Subject Matter	Key Provisions
CERC (Conduct of Business) Regulations, 2009	Procedure for petitions, hearings, orders before CERC	Filing requirements; hearing procedure; interim orders; review petitions; representation by advocates
CERC (Terms and Conditions of Tariff) Regulations (as periodically revised)	Cost-based tariff for central generating stations and ISTS	Capital cost norms; O&M expense norms; debt-equity ratio; return on equity; energy charge rate; capacity charge formula
CERC (Open Access in Inter-State Transmission) Regulations, 2008	LTA; MTOA; STOA to ISTS	Eligibility; application procedure; connectivity norms; charge computation; curtailment principles
CERC (Grant of Connectivity and GNA) Regulations, 2022	Connectivity; General Network Access for RE and hybrid projects	GNA eligibility; connectivity charges; network access charges; curtailment framework for RE
CERC (Power Market) Regulations, 2021	Power Exchanges; market segments; market coupling	Market coupling of IEX and PXIL; Day-Ahead Market; Real-Time Market; Green DAM; exchange governance
CERC (Sharing of ISTS Charges and Losses) Regulations, 2020	Transmission charge allocation across ISTS users	Postage stamp method for RE; flow-based method for conventional; zonal pricing

CERC (Ancillary Services) Regulations	Framework for ancillary services including secondary and tertiary reserves	Procurement of regulation and spinning reserve; payment mechanism; balancing responsibility
CERC (Terms and Conditions for RE Tariff) Regulations	Capital cost and financial norms for RE projects under Section 62 tariff	Benchmark capital cost; debt equity; PLF norms; O&M expense norms by RE technology

5.4 Cost-of-Service Tariff Regulation: Methodology and Principles

The cost-of-service (or cost-plus) methodology of tariff regulation applied by CERC for central generating stations and ISTS assets is designed to ensure that regulated entities can recover their prudently incurred costs and earn a reasonable return on their investment, without being able to earn excessive profits at the expense of consumers. The methodology involves a multi-step process: determination of the capital cost eligible for tariff recovery; calculation of the annual fixed charge (comprising depreciation, interest on loans, return on equity, operation and maintenance expenses, and interest on working capital); and calculation of the energy charge (comprising the fuel cost based on normative heat rate and the applicable fuel price).

The normative parameters specified by CERC for different categories of generating stations — including normative annual plant availability factor (NAPAF), normative heat rate, normative auxiliary consumption factor, and normative operation and maintenance expenses — are based on the achievable performance of the relevant technology at the current state of the art, with an appropriate adjustment to incentivise operational efficiency. Generators who perform better than the normative parameters earn additional revenue (from selling additional electricity at the variable cost rate); generators who perform below the normative parameters receive lower revenue. This incentive mechanism rewards operational efficiency and penalises underperformance within the overall cost-of-service framework.

5.5 Tariff Determination under Section 63: Competitive Bidding Framework

Section 63 of the Electricity Act, 2003, as noted in the discussion of Part V above, provides the alternative tariff determination pathway through competitive bidding. The Central Government has issued guidelines for competitive procurement of electricity capacity, covering both conventional and renewable energy generation and providing a detailed framework for the conduct of competitive bidding by procurers (distribution utilities or central agencies) and the adoption of competitively discovered tariffs by the regulatory commissions.

Under the Section 63 framework, the Appropriate Commission's role in tariff adoption is limited to ensuring that the competitive bidding process was conducted in accordance with the applicable guidelines — it does not re-examine the merits of the tariff offered by the winning bidder or scrutinise the underlying cost assumptions. This limited review is appropriate because the competitive process itself, if conducted fairly and transparently with adequate participation by qualified bidders, provides sufficient assurance of value-for-money procurement. CERC has issued determinations under Section 63 in a large number of cases covering the procurement of conventional thermal power, large hydro power, solar power, wind power, small hydro power, biomass power, and storage projects.

5.6 Advisory Functions and Policy Role of CERC

Section 79(1)(f) requires CERC to advise the Central Government on formulation of the National Electricity Policy, the National Electricity Plan, and in matters relating to the development of the electricity industry. CERC's advisory function is exercised through formal advisory opinions provided at the request of the Central Government and through CERC's participation in the consultative process for the development of policy documents, regulations, and guidelines. CERC's deep engagement with the technical and commercial realities of the electricity sector — through its tariff and market regulatory functions — provides a strong empirical basis for its advisory opinions on matters of policy.

CERC has also exercised its advisory role through the mechanism of suo motu proceedings initiated by the Commission to examine systemic issues in the electricity sector. In such proceedings, CERC constitutes a committee of experts, invites public submissions, conducts hearings, and issues advisory opinions or directions intended to guide policy or improve regulatory practice. Suo motu proceedings initiated by CERC have addressed matters including: the financial health of distribution utilities and its implications for generator payment security; the framework for battery energy storage systems; the design of the ancillary services market; and the regulatory framework for electric vehicle charging infrastructure.

CHAPTER SIX

State Electricity Regulatory Commissions

State-Level Jurisdiction, Tariff Powers, Consumer Protection, and Multi-Year Tariff Framework

State Electricity Regulatory Commissions (SERCs) are the regulatory authorities closest to the daily realities of electricity supply and consumption in India. Their decisions on retail tariffs, distribution utility performance standards, open access conditions, and consumer complaint redressal directly affect every household, business, and industrial enterprise in the country.

6.1 Establishment and Constitutional Basis of SERCs

State Electricity Regulatory Commissions are established under Section 82 of the Electricity Act, 2003. Section 82(1) provides: "Each State Government shall, within a period of six months from the appointed date [i.e., from 10 June 2003], by notification, establish a State Commission." The mandatory character of this provision — using the word "shall" rather than "may" — reflects Parliament's determination that independent electricity regulation at the state level is not an option but an obligation for every state government. The failure to establish a SERC within the specified period would potentially leave a state's electricity sector without an independent regulatory authority, with adverse consequences for investment, consumer protection, and competitive market development.

In states that had already established State Electricity Regulatory Commissions under the Electricity Regulatory Commissions Act, 1998 or under state-level reform legislation (such as Orissa, Andhra Pradesh, Haryana, and Gujarat), the existing commissions were recognised as SERCs for the purposes of the 2003 Act, providing continuity of regulatory oversight and avoiding disruption to ongoing regulatory proceedings. In states that had not yet established regulatory commissions, the 2003 Act provided the statutory mandate and framework for establishment, and most states have now established their SERCs, though the pace and completeness of establishment varied considerably.

6.2 Composition and Qualifications of SERC Members

A State Electricity Regulatory Commission typically comprises a Chairperson and two or more Members, appointed by the relevant state government on the recommendation of a Selection Committee constituted under Section 85 of the Act. Section 85 specifies the composition of the Selection Committee, which must include a person who is a Judge of the High Court of the relevant state (as Chairperson of the Selection Committee), the Chief Secretary of the state government, the Chairperson of the state's electricity supply companies or the highest administrative official of the state's electricity sector, and a person nominated by the CERC Chairperson.

The qualification requirements for the Chairperson of a SERC are specified in Section 84, which requires the Chairperson to be a person who is or has been a Judge of the High Court of the state, or a person of ability and standing with adequate knowledge of, and experience in, problems relating to engineering, finance, commerce, economics, law, or management. In practice, most state governments have appointed retired High Court Judges as Chairpersons of their SERCs, which is appropriate given the quasi-judicial character of the Commission's adjudicatory functions and the importance of judicial standards of fairness and due process in regulatory proceedings that significantly affect the interests of utilities, consumers, and investors.

The Members of a SERC must be persons of ability and standing having adequate knowledge of, and experience in, the areas specified in Section 84(1)(b). In practice, SERCs typically have Members with technical background (electrical engineering, power systems) and financial or administrative background, providing the multi-disciplinary expertise needed for effective electricity regulation. The diversity of expertise on the Commission is important for the quality of regulatory decision-making: tariff determination requires financial and accounting expertise; technical standard-setting and compliance monitoring requires engineering expertise; and adjudication of disputes requires legal expertise and procedural fairness.

6.3 Functions of State Commissions — Section 86 in Detail

Section 86 of the Electricity Act, 2003, specifying the functions of the State Commissions, is one of the most consequential provisions in the Act. The functions it enumerates collectively constitute the regulatory mandate of the SERCs over the intra-state electricity sector, establishing the scope and content of state-level electricity regulation.

6.3.1 Determination of Tariff — Section 86(1)(a)

The function of determining the tariff for generation, supply, transmission, and wheeling of electricity within the state, including the tariff for retail supply of electricity to consumers, is the most commercially significant and politically sensitive of the SERC's functions. The determination of retail electricity tariffs for domestic, agricultural, commercial, and industrial consumers directly affects the electricity bills of millions of consumers, the revenues and financial health of distribution utilities, and the competitiveness of industry in the relevant state.

The tariff determination process before a SERC is a formal quasi-judicial proceeding in which the distribution licensee (or other applicant) files a tariff petition setting out its proposed tariff for the ensuing regulatory period, accompanied by detailed financial statements, cost projections, load forecasts, and assumptions about capital expenditure, operation and maintenance expenses, distribution losses, and other relevant parameters. The Commission publishes the petition and invites objections and suggestions from the public, including consumer organisations, industrial associations, agricultural bodies, and other stakeholders. After considering the objections and suggestions and conducting oral hearings, the Commission determines the tariff through a reasoned order that addresses the principal objections raised and sets out the Commission's findings on each category of costs and revenues.

The political sensitivity of retail tariff determination arises from the fact that electricity is an essential service consumed by every household and business, and that decisions about tariff levels directly affect the disposable income of ordinary consumers and the cost structure of businesses. The agricultural tariff is particularly politically sensitive in most Indian states, as farming communities are significant political constituencies and agricultural electricity tariffs are typically held well below the cost of supply through cross-subsidisation and direct state budget subsidies. The SERC is required by the Tariff Policy to progressively rationalise these cross-subsidies over time, while ensuring that the pace of rationalisation is socially manageable and does not impose undue hardship on agricultural or domestic consumers in the lower income segments.

6.3.2 Grant of Licences — Section 86(1)(b)

The function of granting licences to persons seeking to act as transmission licensees, distribution licensees, or electricity traders within the state is a core institutional function of the SERC. In exercising its licensing function, the SERC acts as the gatekeeper for entry into the electricity supply business in the state, ensuring that only entities with the financial, technical, and organisational capacity to discharge their regulatory obligations are licensed to operate. The licensing function is complemented by the Commission's ongoing supervisory role over licensed entities: the SERC monitors the compliance of licensees with their licence conditions, receives periodic reports from licensees on their operational and financial performance, and takes regulatory action against licensees who fail to comply with their obligations.

6.3.3 Renewable Purchase Obligations — Section 86(1)(e)

Section 86(1)(e) requires the State Commission to promote cogeneration and generation of electricity from renewable sources of energy by providing suitable measures for connectivity with the grid and sale of electricity to any person, and also to specify, for purchase of electricity from such sources, a percentage of the total consumption of electricity in the area of a distribution licensee. This provision is the statutory basis for the Renewable Purchase Obligation (RPO) framework — one of the most important mechanisms for promoting renewable energy in India.

The RPO framework requires distribution licensees (and, in many states, open access consumers and captive consumers) to procure a specified percentage of their total electricity consumption from renewable energy sources. The SERC specifies RPO targets separately for different categories of renewable energy — solar, non-solar wind, biomass, small hydropower, and others — and sets out an RPO trajectory covering several years that progressively increases the renewable energy requirement. The Tariff Policy and the Ministry of New and Renewable Energy provide national guidance on RPO targets and trajectories, which SERCs are expected to align with or exceed in their state-specific specifications.

Compliance with RPO obligations can be demonstrated in two ways: by physically procuring the required percentage of electricity from renewable sources under long-term or short-term PPAs; or by purchasing Renewable Energy Certificates (RECs) from the national market. RECs are tradable certificates representing the generation of one megawatt-hour of electricity from renewable sources, which can be purchased by obligated entities to demonstrate compliance with their RPO without requiring them to enter into direct PPAs with renewable generators in their state or region. The REC mechanism creates a national market for renewable energy attributes and allows the RPO to function as a market-based instrument for promoting renewable energy investment.

6.3.4 Consumer Protection Functions — Sections 86(1)(f) and 57–59

Section 86(1)(f) vests the State Commission with the function of fixing standards of performance for licensees and the quality of service to be provided to consumers. In exercise of this function, SERCs issue Standards of Performance (SoP) regulations that specify quantitative performance standards for distribution licensees covering: the timelines within which connections must be provided to new consumers (typically 15–30 days for LT connections); the accuracy requirements for electricity meters; the frequency and duration of power interruptions that are permissible without triggering automatic compensation payments; the response time for addressing consumer complaints; and the voltage quality standards at consumer premises.

The Consumer Grievance Redressal Forum (CGRF) established under Section 42(5) of the Act, in accordance with SERC guidelines, provides a first-level dispute resolution mechanism for electricity consumers. The CGRF is constituted by the distribution licensee and includes consumer representatives alongside utility officials, providing a structured and accessible forum for resolution of common consumer complaints without the formality of a Commission proceeding. The decisions of the CGRF are binding on the distribution licensee, though a consumer dissatisfied with the CGRF's decision may appeal to the Electricity Ombudsman constituted by the SERC under Section 42(6).

6.4 Multi-Year Tariff Framework: Design, Principles, and Practice

The Multi-Year Tariff (MYT) framework is the predominant approach to distribution tariff regulation in India, adopted in some form by most SERCs following the guidance of the Tariff Policy and CERC's regulatory experience. The MYT framework is designed to address several of the structural weaknesses of annual tariff determination: regulatory uncertainty for investors arising from the unpredictability of annual tariff revisions; perverse incentives for utilities to over-spend on capital expenditure to inflate their asset base; insufficient incentives for operational efficiency improvement; and the high administrative burden of annual tariff proceedings on both the Commission and the regulated entities.

Under the MYT framework, the SERC determines a "control period" of three to five years, during which the key tariff parameters — including the capital expenditure plan, normative operation and maintenance expenses, distribution loss trajectory, and the schedule for cross-subsidy reduction — are set at the beginning of the period and remain substantially fixed. The utility operates within these predetermined parameters and bears the efficiency risk for controllable costs (i.e., it retains savings from achieving better operational performance than the normative parameters, but absorbs any additional costs arising from operational inefficiency). For uncontrollable costs — primarily fuel cost and bulk power purchase cost — the MYT framework typically provides for annual true-up adjustments to reflect actual cost variations.

6.4.1 Control Period Setting and Annual True-Up

At the beginning of each control period, the SERC conducts a comprehensive tariff determination proceedings in which the utility files a detailed Multi-Year Tariff Petition (MYT petition) covering the entire control period. The MYT petition includes: the utility's capital expenditure plan for the control period with justification for proposed investments; the proposed aggregate revenue requirement for each year of the control period; the projected distribution losses and the proposed trajectory for loss reduction; the proposed retail tariff structure for each consumer category; and the proposed cross-subsidy rationalisation schedule. The Commission determines the MYT parameters through a reasoned order and specifies the approved aggregate revenue requirement, the approved distribution loss trajectory, and the retail tariff schedule for the control period.

During the control period, the Commission conducts annual "true-up" proceedings in which it reconciles the approved parameters with the utility's actual performance and costs in the preceding year. The true-up proceeding allows the utility to recover under-recoveries arising from factors outside its control (such as higher-than-projected bulk power purchase costs or demand growth different from the projected trajectory) and requires the utility to pass on over-recoveries (arising from lower actual costs or higher actual revenues than the approved amounts) to consumers. The annual true-up mechanism ensures that the MYT framework is not a mechanism for systematic over-recovery or under-recovery but a dynamic equilibrium in which the approved parameters are regularly calibrated to actual outcomes.

6.5 AT&C Loss Reduction: Regulatory Mechanism

Aggregate Technical and Commercial (AT&C) losses represent the percentage of electricity units that enter the distribution system but are not billed to and recovered from consumers, due to a combination of technical losses in the distribution network (transformer losses, line losses, resistive losses) and commercial losses (theft, metering errors, billing inefficiencies, non-recovery of billed amounts). AT&C losses are a critical performance indicator for distribution utilities and one of the most important regulatory concerns for SERCs, as high AT&C losses represent a direct cost burden on the utility, a subsidy to those who abstracted electricity illegally or free of charge, and a contribution to the financial stress of the distribution sector.

The AT&C loss reduction framework under the MYT regime typically works as follows: the SERC specifies an approved AT&C loss level for the utility at the beginning of the control period, representing the Commission's assessment of achievable performance based on the utility's historical performance, the condition of its distribution infrastructure, and the experience of comparable utilities. The approved AT&C loss level serves as the benchmark against which the utility's actual performance is measured. If the utility achieves AT&C losses below the approved level, it retains the resulting financial benefit (additional revenue from units otherwise considered lost). If the utility's actual AT&C losses exceed the approved level, it bears the financial consequences of the excess losses without being able to pass them through to consumers in subsequent tariff determinations. This approach creates a direct financial incentive for distribution utilities to invest in AT&C loss reduction measures including network upgradation, consumer indexing, smart metering, and anti-theft enforcement.

SERC	State	Key Regulatory Features	Notable Regulatory Achievements
MERC	Maharashtra	Comprehensive MYT; active consumer representation; detailed SoP regulations; robust CGRF and Ombudsman	Pioneer in multi-year tariff; significant AT&C loss reduction; comprehensive open access framework
GERC	Gujarat	Early reformer; strong industrial consumer base; proactive RE procurement regulation	Orissa-model reform heritage; significant industrial tariff rationalisation; strong DISCOM performance
DERC	Delhi	Privatised distribution framework; regulatory compact for performance improvement; active consumer engagement	AT&C loss reduction from >55% to single digits in private DISCOMs post-2002 privatisation
TNERC	Tamil Nadu	Large wind energy base; significant agricultural consumer cross-subsidy; evolving solar procurement	First state to develop significant grid-connected wind capacity; large-scale solar procurement
RERC	Rajasthan	Largest solar resource base; significant agricultural subsidy burden; rapid RE capacity addition	Among largest solar capacity states; progressive RPO specification; subsidy management framework

KERC	Karnataka	Hydro-thermal-RE mix; significant biomass cogeneration; evolving open access framework	Balanced generation mix regulation; significant hydro tariff cases; RE procurement leadership

CHAPTER SEVEN

Joint Electricity Regulatory Commissions & Appellate Tribunal for Electricity

JERC Framework, APTEL Constitution, Jurisdiction, Procedure, and Judicial Interface

The Appellate Tribunal for Electricity is the keystone of the electricity adjudicatory architecture. As the sole appellate forum for orders of CERC and all SERCs, APTEL brings specialised judicial-technical expertise to bear on the complex regulatory disputes that are an inevitable feature of a sector as economically significant and technically complex as electricity.

7.1 Joint Electricity Regulatory Commissions — Section 83

Section 83 of the Electricity Act, 2003 provides for the constitution of Joint Electricity Regulatory Commissions (JERCs) to serve as the regulatory authority for two or more states or Union Territories. The JERC mechanism is a pragmatic solution to the challenge of extending the benefits of independent electricity regulation to smaller states and Union Territories that may lack the financial, administrative, or human resource capacity to establish and sustain their own full-scale regulatory commission.

The Central Government may, by notification in the Official Gazette, constitute a Joint Commission for two or more states under Section 83(1)(a), subject to agreement between the concerned states and with the approval of the Central Government. The terms of the agreement between the participating states would typically address matters including the sharing of costs of the Joint Commission, the representation of each state's interests in the Commission's proceedings, and the mechanism for resolving any differences in regulatory policy between the participating states. The Joint Commission exercises in relation to each participating state all the functions that a State Commission would exercise under Section 86 of the Act, with the adjustments necessary to reflect the multi-state context.

Section 83(1)(b) provides for the Central Government to constitute a Joint Commission for Union Territories without legislatures. The Joint Electricity Regulatory Commission for Goa, Daman and Diu, Dadra and Nagar Haveli, Andaman and Nicobar Islands, Lakshadweep, and Puducherry (JERC-UT) was established by the Central Government to exercise regulatory functions over these Union Territories. The JERC-UT has issued tariff orders, licensing decisions, and other regulatory determinations for electricity utilities in the Union Territories within its jurisdiction, applying the same regulatory principles as the SERCs while adapting to the specific characteristics of the electricity systems in these smaller jurisdictions.

7.2 Appellate Tribunal for Electricity — Constitution and Character

The Appellate Tribunal for Electricity (APTEL) is constituted under Section 110 of the Electricity Act, 2003. Section 110(1) provides that "The Central Government shall, by notification, establish an Appellate Tribunal to be known as the Appellate Tribunal for Electricity to hear appeals against the orders of the adjudicating officers or the Appropriate Commission under the Act." The use of the word "shall" makes the establishment of APTEL a mandatory statutory obligation of the Central Government, not a discretionary matter.

APTEL is a specialised appellate tribunal of a character unique in the Indian administrative law landscape: it combines the judicial authority of a court with the technical expertise of a regulatory body, enabling it to examine both the legal propriety and the technical and economic soundness of Commission orders. This dual character reflects the recognition that effective appellate review of electricity regulatory decisions requires not only expertise in administrative law and due process but also a sufficient understanding of electricity technology, economics, and market design to assess whether the Commission's technical and economic conclusions are defensible. The creation of a specialised tribunal with this combined expertise, rather than routing electricity regulatory appeals through the general High Courts, was intended to produce faster, more expert, and more consistent appellate review of Commission decisions.

7.2.1 Composition of APTEL — Judicial and Technical Members

The Chairperson of APTEL is required to be a serving or retired Judge of the Supreme Court of India, or the Chief Justice of a High Court. This requirement places the judicial authority of APTEL at the highest level in the Indian judicial hierarchy (below the Supreme Court itself), reflecting the importance and complexity of the regulatory disputes that APTEL is called upon to resolve. The elevation of APTEL's judicial leadership to Supreme Court level also ensures that APTEL's decisions carry commensurate authority and are respected by lower courts and regulatory institutions.

APTEL's Judicial Members are required to be Judges of a High Court, while Technical Members are required to be persons of ability, integrity, and standing having knowledge and experience of, and capacity in, dealing with problems relating to economics, commerce, power, energy, industry, administration, or technical matters relating to the electricity sector. The specification of "power" and "energy" as specific areas of technical competence for Technical Members ensures that the bench considering electricity regulatory appeals includes at least some members with direct experience in the electricity sector's technical and commercial dimensions. The combination of judicial rigor (from the Chairperson and Judicial Members) and technical expertise (from the Technical Members) is fundamental to APTEL's identity as a specialised regulatory appellate body.

7.3 Jurisdiction of APTEL — Section 111 in Detail

Section 111(1) provides that "any person aggrieved by any decision or order of an adjudicating officer or the Appropriate Commission under the Act may file an appeal to the Appellate Tribunal in such form, along with such fee, as may be prescribed." This provision establishes APTEL's appellate jurisdiction in the broadest possible terms: any person aggrieved, any decision or order, any adjudicating officer or Appropriate Commission. The comprehensiveness of this jurisdictional grant ensures that no regulatory decision of CERC or a SERC falls outside APTEL's appellate reach.

The phrase "any person aggrieved" has been interpreted broadly by APTEL and the courts to encompass not only the immediate parties to the regulatory proceeding before the Commission but also any other person who is directly and adversely affected by the Commission's order. This includes: distribution utilities affected by a tariff order for a generating station from which they purchase power; open access consumers affected by an order on open access charges; generators affected by a grid code compliance order; and traders affected by a licensing order. Consumer organisations and public interest groups have also been recognised as "persons aggrieved" in cases where the Commission's order has implications for the interests of the consumers they represent.

Section 111(2) — Grounds of Appeal

Section 111(2) of the Electricity Act, 2003 provides: "Every appeal filed under sub-section (1) shall be dealt with by it as expeditiously as possible and endeavour shall be made by it to dispose of the appeal finally within one hundred and eighty days from the date of filing of the appeal." This provision reflects Parliament's intention that electricity regulatory appeals be resolved expeditiously, recognising that prolonged uncertainty about the validity of Commission orders has adverse commercial consequences for electricity sector participants. In practice, however, the 180-day target has often proved aspirational given the volume and complexity of appeals before APTEL.

7.4 Powers of APTEL — Section 120

Section 120 of the Electricity Act, 2003 specifies the powers of the Appellate Tribunal. APTEL is vested with the same powers as a civil court under the Code of Civil Procedure, 1908 in respect of: summoning and enforcing the attendance of any person and examining him on oath; requiring the discovery and production of documents; receiving evidence on affidavits; issuing commissions for the examination of witnesses or documents; reviewing its decisions; dismissing an application for default or deciding it ex parte; and any other matter which may be prescribed. These powers ensure that APTEL can effectively manage the complex evidentiary and procedural dimensions of electricity regulatory appeals.

APTEL's most significant substantive power is the power to confirm, modify, or set aside the order appealed against. APTEL may also remand the matter to the Commission for fresh consideration or hearing, which is particularly appropriate where the Commission has failed to consider relevant evidence, has acted in breach of natural justice, or has addressed its decision on an incorrect legal basis that requires a fresh exercise of judgment. APTEL may exercise these powers in relation to any aspect of the Commission's order — including its findings on questions of fact, its conclusions on questions of law, its exercise of regulatory discretion, and its directions and conditions imposed on parties.

7.5 Procedure before APTEL

Proceedings before APTEL are governed by the Appellate Tribunal for Electricity (Conduct of Business) Regulations, 2007, as amended from time to time. The Regulations specify detailed procedural requirements covering: the form and content of appeal memoranda; the fee payable on filing an appeal; the service of notice on respondents and other parties; the exchange of statements of reply and rejoinder; the filing of written submissions and documents; the procedure for oral hearings; the mechanism for interim orders and stay of Commission orders; the procedure for examination of expert witnesses; and the format and communication of APTEL's orders.

An appeal to APTEL must be filed within 45 days from the date of the order appealed against. However, APTEL has the power to condone delay in filing an appeal if the appellant can demonstrate sufficient cause for the delay. The question of what constitutes "sufficient cause" for delay has been the subject of considerable judicial debate, with APTEL generally applying the standard that cause is sufficient if it is beyond the appellant's control and if the appellant acted with reasonable diligence in initiating the appeal once it became aware of the order. Mere ignorance of the legal remedy or indolence on the part of the appellant do not constitute sufficient cause for condoning delay.

7.5.1 Stay of Commission Orders

The power of APTEL to stay Commission orders pending the hearing and disposal of an appeal is one of the most commercially significant aspects of APTEL's jurisdiction. A stay of a tariff order, for instance, prevents the implementation of the revised tariff during the pendency of the appeal, which may have significant financial consequences for both the utility (which may be entitled to higher tariffs under the appealed order) and the consumers (who would otherwise have to pay higher electricity bills during the appeal period). APTEL's practice on stay applications has evolved in the direction of requiring the applicant for a stay to demonstrate both a prima facie case on the merits of the appeal and that the balance of convenience favours grant of a stay, taking into account the consequences of granting or refusing the stay for all parties affected.

7.6 Appeal to the Supreme Court — Section 125

Section 125 of the Electricity Act, 2003 provides that any person aggrieved by any decision or order of APTEL may file an appeal to the Supreme Court of India within sixty days from the date of communication of the decision or order of APTEL, on any one or more of the grounds specified in Sections 100 of the Code of Civil Procedure, 1908. The reference to Section 100 of the CPC — which deals with second appeals on questions of law — suggests that the statutory appeal to the Supreme Court under Section 125 is intended to be limited to questions of law rather than pure questions of fact. However, in practice the Supreme Court has exercised its appellate jurisdiction under Section 125 more broadly than a strict reading of the Section 100 limitation would suggest, and has re-examined factual and technical findings of APTEL in cases where the Court is satisfied that APTEL's conclusions are perverse or unsupported by the evidence on the record.

The Supreme Court's oversight of APTEL's decisions, while exercised with appropriate deference to the technical expertise of APTEL, has been an important check on the consistency and quality of electricity regulatory adjudication in India. The Supreme Court has delivered authoritative judgments on: the respective jurisdictions of CERC and the SERCs; the principles governing tariff determination for various categories of electricity supply; the scope and conditions of open access; the treatment of change-in-law events in power purchase agreements; and the constitutional validity of various provisions of the Electricity Act, 2003. These judgments, reported in authoritative law journals, constitute a significant body of electricity law jurisprudence that guides practitioners and regulators.

7.7 The Electricity Ombudsman — Section 42(6)

Section 42(6) of the Act provides that every State Commission shall establish the mechanism of an Electricity Ombudsman to settle the grievances of the consumers and to review the performance of the Consumer Grievance Redressal Forum (CGRF). The Ombudsman is appointed by the SERC and is typically a retired judicial officer or senior bureaucrat with experience in consumer affairs or public administration. The Ombudsman's jurisdiction covers: appeals from the decisions of the CGRF; complaints against distribution licensees regarding service quality, billing, metering, and other consumer service matters that were not satisfactorily resolved at the CGRF level; and systemic issues relating to the performance of the CGRF and the distribution licensee's consumer service operations.

The Ombudsman mechanism provides an accessible, low-cost, and expeditious dispute resolution pathway for ordinary consumers who may lack the financial resources or legal expertise to prosecute formal complaints before the SERC. The Ombudsman can direct the distribution licensee to rectify the grievance, provide compensation to the consumer for service failures, and impose costs on the licensee for unreasonable conduct in the handling of consumer complaints. The decisions of the Ombudsman are binding on the distribution licensee and can be challenged only through appropriate legal proceedings before the Commission or the courts.

CHAPTER EIGHT

Licensing Framework under the Electricity Act, 2003

Licence Categories, Application Process, Conditions, Enforcement, and the Open Access Interface

The licensing framework of the Electricity Act, 2003 is one of the principal instruments through which regulatory commissions exercise governance over the electricity supply industry. Through the grant, conditions, monitoring, and revocation of licences, commissions ensure that electricity utilities operate with the financial, technical, and organisational capacity to serve consumers reliably and responsibly.

8.1 The Licensing Requirement — Section 12: Scope and Rationale

Section 12 of the Electricity Act, 2003 establishes the licensing requirement for three specific activities: transmission of electricity, distribution of electricity, and trading in electricity above the prescribed threshold. The section provides that no person shall transmit electricity, distribute electricity, or undertake trading in electricity unless authorised to do so by a licence issued under the Act by the Appropriate Commission, or unless exempt from the requirement to obtain a licence under Section 13 of the Act.

The rationale for the licensing requirement in these three segments of the electricity supply chain is rooted in the economic and public interest characteristics of each activity. Transmission and distribution both exhibit natural monopoly characteristics: the investment in network infrastructure (transmission lines, substations, distribution cables, and transformers) involves large sunk costs, exhibits economies of scale that make duplication economically irrational, and creates facilities that are essential for access to electricity supply. Natural monopoly activities require regulatory oversight through licensing to prevent abuse of monopoly power, ensure non-discriminatory access, and maintain the quality and reliability of service. Electricity trading, while not a natural monopoly, requires licensing because traders operate in a commercially sensitive market in which consumer protection requires assurance of trader credibility and financial capacity.

The deliberate exclusion of electricity generation from the licensing requirement in Section 12, contrasted with the inclusion of the other three activities, reflects the Electricity Act's philosophy that generation is an activity where competition can be introduced and market forces can discipline costs and quality, while transmission, distribution, and (to a lesser extent) trading are activities where regulatory oversight through licensing is necessary to protect public interests that the market alone cannot reliably protect.

8.2 Types of Licences and Issuing Authorities

8.2.1 Transmission Licence

A transmission licence is required for any entity (other than the CTU or STU, which are designated rather than licensed) that wishes to build, own, and operate transmission infrastructure and charge for its use. Private transmission licensees may be developed under the CERC's framework for competitive development of transmission projects, under which private developers bid to build specific transmission elements identified by the CTU's planning process. The winning bidder enters into a Transmission Service Agreement with the CTU and is granted a transmission licence by CERC (for ISTS elements) or by the SERC (for intra-state elements) as a condition of being entitled to receive the tariff determined in the bidding process.

The conditions of a transmission licence specify: the specific transmission system elements (lines, substations, and associated equipment) that the licensee is authorised to construct, own, and operate; the performance standards the licensee must meet in terms of availability and reliability of the transmission system; the obligation to provide non-discriminatory open access to the licensed system; the reporting obligations to the Commission; the mechanism for recovery of transmission tariff; and the conditions for modification and revocation of the licence. Private transmission licensees are subject to the same non-discriminatory access obligations as the CTU and STU under the relevant CERC/SERC regulations.

8.2.2 Distribution Licence

The distribution licence is the most operationally consequential type of electricity licence in the Indian regulatory framework, as it governs the entities responsible for the "last mile" delivery of electricity to consumers. Distribution licences are granted by the SERC of the relevant state to entities seeking to distribute electricity in a specified geographical area (the "area of supply"). The area of supply is a key element of the distribution licence, defining the geographical boundaries within which the licensee has both the right and the obligation to supply electricity to all consumers who request a connection.

The conditions of a distribution licence typically include: the obligation to supply electricity to every consumer in the area of supply on application, subject to the payment of applicable charges and compliance with technical conditions; the obligation to maintain and upgrade the distribution network to meet the demand requirements of consumers in the area of supply; the obligation to comply with the SERC's standards of performance for distribution licensees; the obligation to metering all supply in accordance with SERC metering regulations; the obligation to establish and maintain the Consumer Grievance Redressal Forum and to cooperate with the Electricity Ombudsman; the obligation to comply with the SERC's tariff order; and the obligation to achieve the distribution loss reduction targets specified in the SERC's MYT order.

8.2.3 Trading Licence

The trading licence is required for entities engaging in the purchase of electricity for resale above the threshold prescribed by the Central Government. CERC issues trading licences for inter-state trading, and the SERCs issue trading licences for intra-state trading. CERC categorises trading licensees into two categories based on their financial capacity and trading volume: "unrestricted category" licensees who can trade without any volume ceiling, and "restricted category" licensees whose annual trading volume is capped at a prescribed level. The eligibility criteria for trading licences include minimum net worth requirements (higher for the unrestricted category), track record of experience in the electricity sector, and compliance with CERC's code of conduct for trading licensees.

8.3 Deemed Licences — Section 14: Transitional Framework

Section 14 of the Electricity Act, 2003 provides for "deemed licences" — a transitional mechanism by which existing electricity utilities that were operating under the predecessor legislative framework are treated as having been granted the relevant licence under the 2003 Act without going through the formal application process. This mechanism was essential for ensuring the continuity of electricity supply during the legislative transition: if the entities responsible for generation, transmission, and distribution had been required to obtain fresh licences before they could continue operating, there would have been a potentially catastrophic disruption to electricity supply in the period immediately following the commencement of the Act.

The deemed licensee status of existing electricity utilities was important not only for operational continuity but also for legal certainty regarding the regulatory jurisdiction applicable to their activities. By treating existing utilities as licensees under the 2003 Act, the legislation established clearly that they are subject to the regulatory jurisdiction of the relevant Commission and to the obligations imposed by the Act on licensees, including the open access obligation, the consumer protection obligations, and the obligation to comply with the Commission's tariff and service quality orders. The deemed licensee framework also provided the basis for subsequent regulatory proceedings in which the Commission has reviewed and modified the conditions of the deemed licences of existing utilities to bring them into conformity with the requirements of the 2003 Act framework.

8.4 Licence Application and Grant Process — Section 15

The process for obtaining a licence under the Electricity Act, 2003 is governed by Section 15 and the detailed licensing regulations made by the Appropriate Commission. The general outline of the application and grant process is consistent across the different types of licences, though the specific documentation requirements and substantive evaluation criteria vary according to the type of licence sought. The process involves the following principal stages:

8.4.1 Application Filing

The prospective licensee submits a formal application to the Appropriate Commission, accompanied by the prescribed application fee and the documents specified in the Commission's licensing regulations. For a distribution licence, the required documents typically include: a business plan for the proposed distribution business in the proposed area of supply; audited financial statements demonstrating the applicant's financial capacity; technical credentials including details of the applicant's engineering expertise and operational experience; a draft of the proposed conditions of supply applicable to consumers in the area of supply; and documentation establishing the applicant's legal status (company registration, memorandum and articles of association, etc.).

8.4.2 Public Notice and Objection Period

Upon receipt of a licence application, the Commission publishes a notice of the application in the Official Gazette and in at least two newspapers, inviting objections and suggestions from the public, including affected consumers, existing licensees, and other stakeholders, within a specified period of not less than 30 days. The public notice requirement ensures that the grant of a licence is subject to transparency and public accountability, and that the interests of those who may be directly affected by the licensee's operations are considered before the Commission makes its licensing decision.

8.4.3 Hearing and Determination

After the expiry of the objection period, the Commission conducts a hearing at which the applicant and all persons who have filed objections or suggestions are entitled to be heard. The Commission considers all relevant evidence and submissions, including the applicant's financial and technical qualifications, the desirability of granting a licence from the perspective of consumer welfare and competitive market development, and the concerns raised by objectors. The Commission then determines the application through a reasoned order, which either grants the licence (with specified conditions) or refuses it (with reasons).

8.5 Conditions of Licence — Section 16

Section 16 of the Act provides that every licence shall specify the conditions subject to which the licensee shall be authorised to engage in the relevant activity. The conditions of licence serve two principal functions: they define the scope of the licensee's authorisation (specifying, for instance, the area of supply for a distribution licensee or the specific transmission elements for a transmission licensee); and they establish the obligations that the licensee must fulfil as a condition of retaining its licence (including compliance with technical standards, consumer protection obligations, reporting requirements, and performance standards).

Standard conditions of licence applicable to all categories of licensees include: the obligation to comply with the Act and all regulations, orders, and directions made thereunder; the obligation to maintain proper accounts and records in the form prescribed by the Commission; the obligation to submit periodic reports to the Commission on the licensee's operational and financial performance; the obligation to allow the Commission's authorised officers to inspect the licensee's premises, records, and installations; the obligation to comply with any direction issued by the Commission; and the obligation not to assign or transfer the licence without the prior approval of the Commission.

8.6 Modification and Revocation of Licences — Sections 18–19

Section 18 of the Electricity Act, 2003 provides that the Appropriate Commission may, after giving not less than three months notice to the licensee and after considering any cause shown by the licensee against the proposed modification, modify any condition of the licence if, in its opinion, such modification is required in the public interest or in the interest of the consumers or to prevent undue hardship to the licensee or to prevent any harm to the public. The power to modify licence conditions is an important regulatory tool that enables the Commission to adapt the regulatory compact governing a licensee's operations to changing circumstances without requiring the grant of a fresh licence.

Section 19 provides for the revocation of a licence by the Commission on the occurrence of any of the specified grounds, which include: failure of the licensee to comply with any condition of the licence or with the provisions of the Act; bankruptcy or insolvency of the licensee; making of a false statement in obtaining the licence; failure to make payments due to the Commission or other entities as required; and cessation of the licensee's engagement in the activities covered by the licence for a continuous period exceeding two months without reasonable cause.

The revocation of a distribution licence is an action of considerable gravity given the essential nature of electricity distribution as a public service, and the Commission must ensure continuity of supply to consumers in the event of revocation. Section 20 of the Act provides that where a licence is revoked or surrendered, the Commission shall, as soon as practicable, arrange for the supply of electricity to all consumers in the area of supply by an alternative licensee. The provisions for ensuring continuity of supply reflect the legislature's recognition that the regulatory objective of maintaining effective oversight of licensee performance cannot come at the cost of disruption to the essential electricity supply on which ordinary consumers depend.

Licence Type	Activity Covered	Issuing Authority	Key Conditions	Performance Standards
Transmission Licence	Construction and operation of transmission lines and associated infrastructure	CERC (ISTS); SERC (intrastate)	Non-discriminatory OA; technical standards compliance; availability guarantee; reporting	Transmission system availability; forced outage rate; maintenance compliance
Distribution Licence	Distribution of electricity to consumers in designated area of supply	SERC of relevant state	Duty to supply; QoS standards; AT&C loss targets; metering; CGRF establishment	SAIFI; SAIDI; metering accuracy; connection timelines; complaint resolution time
Trading Licence (Unrestricted)	Purchase for resale without volume ceiling	CERC (inter-state); SERC (intra-state)	Net worth maintenance; code of conduct; quarterly reporting; security deposit	Settlement compliance; payment timeliness; contract counterparty creditworthiness
Trading Licence (Restricted)	Purchase for resale up to prescribed annual volume	CERC (inter-state); SERC (intra-state)	Volume ceiling; lower net worth requirement; code of conduct; reporting	Volume monitoring; settlement compliance; code of conduct adherence

CHAPTER NINE

Generation, Transmission & Distribution: Legal Regime

De-licensing, Competitive Procurement, Open Access, Consumer Rights, and Market Development

The legal regime governing the three principal segments of the electricity supply chain — generation, transmission, and distribution — is where the abstract principles of the Electricity Act, 2003 are translated into operational realities for generators, network operators, consumers, and investors. This chapter examines the substantive legal framework for each segment and the commercial and regulatory interfaces between them.

9.1 The De-licensed Generation Regime: Legal Framework and Operational Reality

Section 7 of the Electricity Act, 2003, by removing the licensing requirement for electricity generation (subject to connectivity standards compliance), created the legal conditions for an unprecedented expansion of private sector participation in Indian electricity generation. The de-licensed generation framework has enabled: the development of large-scale private thermal power projects (including the ultra mega power projects and other large coal and gas-based projects developed from the mid-2000s onward); the rapid scale-up of privately developed renewable energy projects including wind, solar, small hydro, and biomass projects across the country; and the development of captive power plants by industrial consumers seeking to secure reliable and cost-effective electricity supply for their operations.

The de-licensing of generation does not mean the complete removal of regulation from the generation segment. Generating companies developing new projects must comply with: environmental and forest clearance requirements under the Environment Protection Act, 1986 and the Forest Conservation Act, 1980; land acquisition requirements under the Right to Fair Compensation and Transparency in Land Acquisition, Rehabilitation and Resettlement Act, 2013; the CEA's technical standards for connectivity to the grid; the terms of any power purchase agreement with distribution utilities or other buyers (which are approved by the regulatory commission under Sections 62 or 63 of the Act); grid code obligations under the IEGC; and, for central public sector generating companies, tariff regulation by CERC under the cost-of-service framework. The de-licensing removes one specific regulatory barrier — the requirement for prior Commission approval of the decision to develop a generating station — while leaving the project development process subject to a comprehensive array of other regulatory and contractual requirements.

9.2 Power Purchase Agreements: Legal Architecture and Key Provisions

The Power Purchase Agreement (PPA) is the foundational commercial instrument governing the relationship between a generator and its electricity buyer (typically a distribution utility). PPAs in the Indian electricity sector are long-term contracts — typically 25 years for most conventional and renewable energy projects — that define the commercial terms on which the generator will supply electricity to the buyer over the contract period. The longevity of these contracts reflects the long useful life of electricity generation assets, the need for generators to secure long-term revenue certainty to support project financing, and the interest of distribution utilities in securing reliable long-term electricity supply for their consumers.

9.2.1 Key Provisions of a PPA

The principal provisions of a power purchase agreement in the Indian electricity sector include: installed capacity and contracted capacity (the maximum capacity the generator commits to make available); the scheduled generation or energy commitment (the energy the generator commits to supply annually or over the contract period); the tariff structure (including capacity charges, energy charges, supplementary charges, and incentive provisions); the scheduling and despatch provisions (governing how the generator receives despatch instructions and the consequences of non-compliance); the payment mechanism (including payment due dates, late payment charges, and payment security mechanisms); the force majeure provisions (specifying events beyond the parties' control that excuse performance and the consequences of prolonged force majeure events); the change-in-law provisions (specifying how regulatory or legal changes affecting the generator's costs or revenues are allocated between the parties); and the termination provisions (specifying the events entitling either party to terminate the agreement and the compensation payable on termination).

9.2.2 Change-in-Law Provisions and Regulatory Risk Allocation

The change-in-law provisions of power purchase agreements have been the subject of extensive regulatory and judicial scrutiny in India, as the dynamic regulatory environment of the electricity sector frequently generates events that affect the cost structures of generating companies. The general principle of change-in-law provisions is that regulatory changes affecting the generator's costs or revenues that occur after the date of the PPA (or after a specified cut-off date such as the bid submission date in competitive procurement) should be allocated to the buyer rather than absorbed by the generator, on the grounds that the generator had priced the PPA on the basis of the regulatory environment prevailing at the time of bidding and should not bear the financial consequences of subsequent regulatory changes.

Major change-in-law events that have been the subject of regulatory and judicial proceedings in India include: changes in coal allocation policy affecting the cost of coal supplied to thermal power plants; imposition of customs duty on imported solar modules and cells (in the context of solar PPAs); changes in goods and services tax affecting the cost of inputs; changes in environmental regulations imposing additional compliance costs; and changes in transmission charges and grid code requirements. The resolution of change-in-law claims requires a careful analysis of: whether the event constitutes a "change in law" within the definition specified in the PPA; whether the event causes an increase or decrease in costs or revenues that is directly attributable to the change in law; and the appropriate mechanism for determining and verifying the financial impact of the change-in-law event.

9.3 Section 63 Competitive Bidding: Framework and Implementation

Section 63 of the Electricity Act, 2003, read with the competitive bidding guidelines issued by the Central Government under Section 63, constitutes the legal architecture for the competitive procurement of electricity capacity in India. The competitive bidding framework has fundamentally transformed the economics of electricity procurement in India, driving sustained reductions in tariffs for thermal, renewable, and storage capacity over the period since the framework was first operationalised.

The competitive bidding process under Section 63 involves the following key stages: the preparation and approval of the Request for Proposal (RFP) document by the procuring entity, subject to regulatory oversight; the issuance of the RFP to prospective bidders qualified under pre-qualification criteria; the receipt and evaluation of bids; the selection of the winning bidder based on the lowest discovered tariff (in a standard tariff-based competitive bid); the execution of the PPA with the winning bidder; and the submission of the PPA to the Appropriate Commission for adoption of the tariff under Section 63. The Commission's role in the Section 63 adoption proceeding is limited to verifying that the competitive bidding process was conducted in accordance with the applicable guidelines and that there are no patent irregularities in the bidding process; the Commission does not re-examine the merits of the tariff bid by the winning bidder.

9.4 Transmission Open Access: ISTS Framework

The CERC (Grant of Connectivity and General Network Access) Regulations, 2022, the latest evolution of the ISTS open access framework, introduced the concept of "General Network Access" (GNA) as the primary access modality for generators connecting to the ISTS. Under GNA, a generator or group of generators from a state or region may access the ISTS on a shared, non-exclusive basis, with the GNA allocation providing a guaranteed level of access to the ISTS network without the need for the generator to secure a project-specific dedicated corridor of transmission capacity. This is a significant conceptual departure from the earlier Long-Term Access framework, under which generators had to identify specific transmission corridors for their projects and secure access to those corridors as a precondition of connection to the ISTS.

The GNA framework is particularly well-suited to renewable energy generation, where the inherent variability of wind and solar output means that dedicated transmission corridors are typically under-utilised at times of low renewable generation and congested at times of peak generation. By allowing renewable generators to share network access capacity, the GNA framework improves the utilisation of the ISTS and reduces the cost of transmission access for individual generators. The framework also facilitates the development of renewable energy capacity in resource-rich areas (such as the high solar irradiation zones of Rajasthan and Gujarat and the high wind resource zones of Tamil Nadu and coastal states) from which transmission capacity to load centres is developed on a shared basis as part of the national transmission planning process.

9.5 Distribution Open Access: Legal Framework and Commercial Dynamics

Open access to the distribution system, governed by Section 42 of the Electricity Act, 2003 and the regulations issued by the SERCs under that provision, enables large consumers to source electricity from generators or traders of their choice rather than having to purchase all their electricity from the incumbent distribution licensee. The distribution open access framework creates the conditions for competitive electricity supply to large industrial and commercial consumers, who can potentially access cheaper electricity by procuring directly from renewable energy generators, independent power producers, or electricity traders, and using the distribution licensee's network merely as a transportation system to deliver the procured electricity to their premises.

The commercial attractiveness of distribution open access to large consumers depends critically on the charges payable for using the distribution licensee's network — particularly the cross-subsidy surcharge (CSS) and the additional surcharge (AS). The CSS is a charge payable by open access consumers under Section 42(4) of the Act, designed to recover from departing consumers a contribution towards the cross-subsidies that would otherwise have been funded from their tariff payments. The AS is a charge payable under Section 42(4) to cover the costs of maintaining standby capacity by the distribution licensee to serve the open access consumer in the event of interruption to its open access supply. The quantum of these charges, and the methodology for their computation, has been a persistent source of regulatory controversy and judicial dispute in the open access domain.

9.6 Consumer Protection: Standards of Service and Compensation

The consumer protection framework established by the Electricity Act, 2003 operates at multiple levels and through multiple institutional mechanisms. At the first level, the statutory duty to supply under Section 43 creates a legally enforceable obligation on distribution licensees to supply electricity to all consumers in their area of supply, providing the fundamental legal guarantee of electricity access. At the second level, the standards of performance specified by SERCs under Section 57 establish the quality benchmarks against which distribution utility performance is measured, creating regulatory accountability for service quality. At the third level, the compensation mechanism under Section 59 provides consumers with a monetary remedy for service failures, creating a direct financial incentive for licensees to meet their service quality obligations. At the fourth level, the CGRF and Ombudsman mechanisms provide accessible and low-cost institutional fora for individual consumer dispute resolution.

The evolution of consumer protection regulation in the electricity sector has been marked by a progressive tightening of performance standards and an expansion of consumer rights. Early standards of performance specified by SERCs were relatively modest and difficult to enforce given the poor baseline performance of many distribution utilities. Over time, SERCs have progressively raised performance standards, expanded the categories of service failures that trigger automatic compensation payments, reduced the timelines for connection and complaint resolution, and introduced new categories of consumer rights including the right to smart metering and the right to rooftop solar net metering. These developments reflect the maturing of the regulatory framework and the growing expectations of electricity consumers as electricity supply becomes more reliable and the expectations of service quality rise accordingly.

CHAPTER TEN

Amendments, Judicial Developments & Reform Agenda

Legislative Amendments, Landmark Judgments, Regulatory Milestones, and the Future of Indian Electricity Regulation

The Electricity Act, 2003, while remarkably durable as a legislative framework, has been subject to ongoing revision through targeted amendments, significant judicial development, and a continuous process of regulatory evolution. Understanding the trajectory of this evolution is essential for anticipating the future direction of electricity regulation in India.

10.1 The Electricity (Amendment) Act, 2007

The Electricity (Amendment) Act, 2007, enacted four years after the principal Act's commencement, introduced targeted modifications addressing specific implementation difficulties that had emerged in the initial period of the Act's operation. The 2007 amendments covered several distinct areas: changes to Section 121, which deals with APTEL's power to give general directions to regulatory commissions; amendments to the provisions relating to the functions and powers of the adjudicating officers appointed under Section 143 for the purpose of adjudicating penalties under the Act; modifications to the penalty provisions in Part X, particularly in relation to electricity theft; and clarifications regarding the jurisdiction of regulatory commissions in relation to matters that had generated interpretive uncertainty in the initial years of the Act's operation.

The 2007 amendments also addressed certain constitutional concerns that had been raised about specific provisions of the principal Act. In particular, the amendments relating to APTEL's powers and jurisdiction were designed to respond to judicial observations about the scope of APTEL's appellate function and the relationship between APTEL's orders and the jurisdiction of the High Courts under Article 226. The amendments sought to clarify that APTEL functions as a court of record with the authority to make binding orders having the force of a High Court decree, while preserving the constitutional jurisdiction of High Courts in appropriate cases.

10.2 Proposed Comprehensive Amendments: The Electricity Amendment Bills

Multiple proposals for comprehensive amendment of the Electricity Act, 2003 have been advanced by the Government of India through draft Bills introduced in Parliament and circulated for public consultation. The principal proposed amendments that have emerged in the successive drafts of the Electricity (Amendment) Bill include the following.

10.2.1 Separation of Content and Carriage in Distribution

The most conceptually significant proposed amendment is the "content and carriage" separation in electricity distribution, which would allow multiple licensed supply companies to use the same distribution network infrastructure to supply electricity to consumers in the same geographical area. Under this proposed model, the distribution network (the "carriage") would be owned and operated by a regulated "distribution wires company" or "wire licensee," while multiple "supply licensees" or "retail supply companies" would compete to supply electricity to consumers over the shared network. This is analogous to the telecom sector model in which multiple telecom service providers compete to provide services over a shared infrastructure of spectrum and fixed-line networks.

The content-carriage separation model is intended to introduce competition into the retail electricity supply segment, which is currently a regulated monopoly in most parts of India. Advocates of this reform argue that competition among supply licensees would incentivise innovation in consumer services, pricing, and renewable energy offerings, and would provide consumers with the ability to choose their electricity supplier based on price, reliability, and green energy content. Critics argue that the technical and administrative complexity of managing multiple supply licensees on the same distribution network is very high, that the costs of the transition from the current regulated monopoly model to a competitive supply model may outweigh the benefits, and that the financial stress of distribution utilities makes them unlikely to support a reform that could further fragment their customer base and undermine their financial position.

10.2.2 Direct Benefit Transfer for Electricity Subsidies

The proposed Direct Benefit Transfer (DBT) mechanism for electricity subsidies would replace the current practice of subsidising electricity supply by allowing distribution utilities to charge below-cost tariffs to specified consumer categories, with a system in which the state government directly transfers the subsidy amount to the bank accounts of eligible consumers, who then pay market-rate tariffs to the distribution utility. This reform is designed to: improve the targeting of subsidies to genuinely deserving consumers; eliminate the distortions created by blanket cross-subsidies that benefit all consumers in a category regardless of their actual need; improve the financial position of distribution utilities by ensuring they receive full cost-reflective tariff payments from all consumers; and increase transparency and accountability in the management of electricity subsidies.

10.2.3 Renewable Purchase Obligations — Strengthened Enforcement

The proposed amendments include provisions for significantly strengthened enforcement of Renewable Purchase Obligations on distribution licensees, open access consumers, and other obligated entities. The current RPO enforcement framework has been criticised for its inadequacy: many obligated entities have consistently fallen short of their RPO targets without facing significant financial consequences, and the regulatory commissions have often been reluctant to impose penalties for RPO non-compliance given the financial stress of distribution utilities and the challenges of renewable energy procurement in some states. The proposed amendments would impose higher penalties for RPO non-compliance and establish clearer mechanisms for the enforcement of Commission orders on RPO.

10.3 Landmark Judicial Pronouncements on Electricity Law

The Supreme Court of India and APTEL have developed a substantial body of electricity law jurisprudence over the two decades since the enactment of the Electricity Act, 2003. The following summarises certain significant legal principles established through judicial decisions. Note: All case citations and holdings should be independently verified from authorised law reports and the official Supreme Court and APTEL websites before reliance in any legal proceeding.

10.3.1 Jurisdiction of APTEL and Bar on High Court Jurisdiction

The Supreme Court has delivered several important decisions on the relationship between APTEL's jurisdiction and the jurisdiction of the High Courts under Article 226 of the Constitution. The Court has affirmed that: (a) APTEL is the exclusive forum for appeals against Commission orders under the Act, and parties aggrieved by such orders must file their appeals before APTEL rather than directly before the High Court; (b) the existence of APTEL as an effective alternative remedy is a strong reason for High Courts to decline to exercise their Article 226 jurisdiction in cases involving challenges to Commission orders; (c) however, the constitutional jurisdiction of High Courts under Article 226 is not ousted by the creation of APTEL, and High Courts may exercise their writ jurisdiction in appropriate cases, particularly where there is a fundamental breach of natural justice or where the Commission has acted without jurisdiction; and (d) the appropriate test for determining whether a High Court should exercise its Article 226 jurisdiction is whether APTEL provides an adequate and efficacious remedy for the specific grievance raised by the petitioner.

10.3.2 Tariff Regulatory Principles — Key Legal Issues

Several important principles of tariff regulatory law have been established through Supreme Court and APTEL decisions. Key legal issues addressed include: the extent to which regulatory commissions are bound by the National Electricity Policy and Tariff Policy in exercising their tariff-setting functions (the Commission must take these policies into account but retains independent regulatory judgment on how they apply to the specific case); the permissible scope of review of previous tariff orders in annual true-up proceedings (the Commission may revisit its earlier assumptions in the true-up proceeding to the extent justified by actual performance data, but cannot reopen settled issues without fresh evidence); the treatment of under-recoveries and over-recoveries in the tariff regulatory process (these must be addressed in subsequent tariff determinations through appropriate true-up mechanisms); and the principles governing the allocation of efficiency gains and efficiency shortfalls between the utility and its consumers in the MYT framework.

10.3.3 Open Access — Key Legal Principles

The legal principles governing the rights and obligations of open access users and the obligations of transmission and distribution licensees in relation to open access have been significantly elaborated through regulatory and judicial decisions. Key principles include: the cross-subsidy surcharge on open access consumers must be determined by the SERC in a manner that is rationally related to the actual cross-subsidy embedded in the tariff of the category of consumers to which the open access consumer would have belonged, and must not be set at a level that effectively denies the open access consumer the economic benefit of competitive sourcing; the additional surcharge under Section 42(4) covers only the cost of maintaining stranded capacity for the benefit of the open access consumer and cannot be extended to cover other costs; and the refusal of open access by a distribution licensee on grounds other than those specified in the Act and the applicable regulations is a breach of the licensee's statutory duty under Section 42(2) and may give rise to regulatory and judicial consequences.

10.4 Regulatory Milestones in the Post-EA 2003 Period

Year	Milestone	Regulatory Significance
2003	Electricity Act, 2003 enacted and brought into force	Comprehensive legislative reform; de-licensing of generation; mandatory open access; APTEL established
2005	National Electricity Policy notified	Policy framework under Section 3; universal service obligation; guidance on tariff rationalisation
2006	Tariff Policy (first comprehensive version) notified	Cost-reflective tariff principles; competitive bidding guidelines; RPO framework articulated
2007	Electricity (Amendment) Act, 2007	APTEL powers clarified; penalty provisions updated; jurisdictional clarifications
2008	CERC Open Access (ISTS) Regulations issued	Framework for long-term access and medium-term OA to ISTS; connectivity conditions
2010	Jawaharlal Nehru National Solar Mission launched; initial competitive solar procurement	First large-scale competitive solar procurement; CERC solar tariff benchmark under Section 62
2011	REC mechanism becomes operational; first REC trading session held	Market-based RPO compliance instrument; CERC REC Regulations operationalised
2013	Southern Regional Grid synchronized with national grid	First truly synchronous national electricity grid; uniform frequency across all regions
2016	Revised Tariff Policy notified; Ujwal DISCOM Assurance Yojana (UDAY) implemented	Enhanced competitive bidding mandate; DISCOM financial restructuring scheme
2019	Real-Time Market launched on Indian Energy Exchange and PXIL	15-minute block trading near real time; improved balancing mechanism for RE integration
2022	CERC GNA Regulations; Green Energy Open Access Rules; PM Surya Ghar Yojana precursor schemes	Flexible ISTS access for RE; 100 kW threshold for green open access; rooftop solar promotion

2023	Carbon Credit Trading Scheme notified under Energy Conservation (Amendment) Act, 2022	India's domestic carbon market; linked to RPO and energy efficiency obligations

10.5 The Future of Indian Electricity Regulation

The Indian electricity sector is undergoing a period of transformation unprecedented since the enactment of the Electricity Act, 2003. The driving forces of this transformation include: the massive planned expansion of renewable energy capacity (with India targeting 500 GW of installed renewable energy capacity by 2030); the rapid deployment of battery energy storage systems as a complement to variable renewable generation; the electrification of the transportation sector through the growth of electric vehicles; the development of green hydrogen as a fuel derived from renewable electricity; the increasing penetration of distributed energy resources including rooftop solar, small wind, and demand-response systems; and the growing importance of digital technology in grid management, consumer services, and energy market operations.

These transformations pose both regulatory challenges and opportunities. The regulatory challenge of integrating large volumes of variable renewable energy into the grid while maintaining system reliability and frequency stability requires new regulatory frameworks for ancillary services, flexible generation, and demand-side management. The development of battery storage as a regulated activity requires new frameworks for the tariff regulation, safety standards, and market participation rules applicable to storage facilities. The growth of electric vehicles raises regulatory questions about the framework for electric vehicle charging infrastructure, the treatment of vehicle-to-grid technologies, and the implications of large-scale EV charging loads for distribution network planning and tariff design. The development of green hydrogen creates new intersections between the electricity regulatory framework and the regulation of gas and hydrogen infrastructure. The increasing digitalisation of the electricity system raises regulatory questions about data governance, cybersecurity, and the ownership and use of smart meter data.

The institutional capability of the regulatory framework to respond to these challenges will depend critically on the quality and independence of the regulatory commissions, the technical expertise of their staff, the quality of data and analysis available to support regulatory decision-making, and the effectiveness of coordination between central and state regulatory authorities. Investment in the institutional capacity of the regulatory commissions — through adequate funding, competitive compensation for regulatory staff, access to technical expertise, and inter-commission learning and collaboration — is an essential complement to the legislative and market design reforms that will shape the future of the Indian electricity sector.

APPENDIX

Statutory Provisions, Regulatory Framework & Glossary

Quick Reference for Legal Practitioners and Sector Professionals

A.1 Selected Key Provisions of the Electricity Act, 2003

Section 2(4) — "Appropriate Commission" Definition

Means — (a) the Central Commission referred to in sub-section (1) of Section 76, in relation to (i) the generating companies specified in sub-clause (i) of clause (b) of sub-section (1) of Section 79; (ii) the generating companies and other persons, if the generating company or persons concerned have a composite scheme for generation and sale of electricity in more than one State; (b) in other cases, the State Commission of the State in which — (i) the generating station is located; (ii) the licensee operates.

Section 7 — De-licensing of Generation

Any generating company may establish, operate and maintain a generating station without obtaining a licence under this Act if it complies with the technical standards relating to connectivity with the grid referred to in clause (b) of Section 73: Provided that the generating company intending to establish a hydro generating station shall, before making an application under Section 15, submit the proposal for the establishment of such generating station to the Appropriate Commission and the Central Authority for the concurrence of the Central Authority.

Section 38(1) — Duties of Central Transmission Utility

It shall be the duty of the Central Transmission Utility to — (a) build, maintain and operate an efficient, co-ordinated and economical inter-State transmission system; (b) provide non-discriminatory open access to its transmission system for use by — (i) any licensee or generating company on payment of the transmission charges; or (ii) any consumer as and when such open access is provided by the State Commission under sub-section (2) of Section 42, on payment of the transmission charges and a surcharge thereon, as may be specified by the Central Commission: Provided that such surcharge shall be utilised for the purpose of meeting the requirement of current level of cross-subsidy.

Section 42(2) — Open Access in Distribution

Every distribution licensee shall, within two years from the appointed date, provide open access to the persons requiring the use of distribution system and such open access shall be subject to availability of adequate infrastructure and compliance with such security standards as may be specified by the State Commission and payment of a surcharge in addition to the charges for wheeling as may be determined by the State Commission: Provided that such surcharge shall be utilised to meet the requirements of current level of cross-subsidy within the area of supply of the distribution licensee.

Section 43(1) — Duty to Supply

Save as otherwise provided in this Act, every distribution licensee, shall, on an application by the owner or occupier of any premises, give supply of electricity to such premises, within one month after receipt of the application requiring such supply: Provided that where such supply requires extension of mains or service lines, the distribution licensee shall supply the electricity to such premises immediately after such extension.

Section 61 — Tariff Determination Principles

The Appropriate Commission shall, subject to the provisions of this Act, determine the tariff in accordance with the provisions of this Act and in doing so, shall be guided by the following, namely: (a) the principles and methodologies specified by the Central Commission for determination of the tariff applicable to generating companies and transmission licensees; (b) the generation, transmission, distribution and supply of electricity are conducted on commercial principles; (c) the factors which would encourage competition, efficiency, economical use of the resources, good performance and optimum investments; (d) safeguarding of consumers' interest and at the same time, recovery of the cost of electricity in a reasonable manner; (e) the principles rewarding efficiency in performance; (f) multi-year tariff principles; (g) that the tariff progressively reflects the cost of supply of electricity at an adequate and improving level of efficiency; (h) the promotion of co-generation and generation of electricity from renewable sources of energy; (i) the National Electricity Policy and tariff policy.

Section 86(1) — Functions of State Commission

The State Commission shall discharge the following functions, namely: (a) determine the tariff for generation, supply, transmission and wheeling of electricity, wholesale, bulk or retail, as the case may be, within the State: Provided that where open access has been permitted to a category of consumers under section 42, the State Commission shall determine only the wheeling charges and surcharge thereon, if any, for the said category of consumers; (b) regulate electricity purchase and procurement process of distribution licensees including the price at which electricity shall be procured from the generating companies or licensees or from other sources through agreements for purchase of power for distribution and supply within the State; (c) facilitate intra-state transmission and wheeling of electricity; (d) issue licences to persons seeking to act as transmission licensees, distribution licensees and electricity traders with respect to their operations within the State; (e) promote co-generation and generation of electricity from renewable sources of energy by providing suitable measures for connectivity with grid and sale of electricity to any person, and also specify, for purchase of electricity from such sources, a percentage of the total consumption of electricity in the area of a distribution licensee.

Section 111(1) — Appeal to Appellate Tribunal

Any person aggrieved by an order made by an adjudicating officer under this Act or an order made by the Appropriate Commission under this Act, except under section 127, may prefer an appeal to the Appellate Tribunal for Electricity: Provided that any person appealing against the order of the adjudicating officer levying any penalty shall, while filing the appeal, deposit the amount of such penalty: Provided further that where in any particular case, the Appellate Tribunal is of the opinion that the deposit of such penalty would cause undue hardship to such person, it may dispense with such deposit subject to such conditions as it may deem fit to impose so as to safeguard the realisation of penalty.

A.2 Glossary of Key Terms

Aggregate Revenue Requirement (ARR)

The total revenue that a distribution licensee is entitled to recover through tariffs in a given year, comprising the cost of bulk power purchase, transmission charges, operation and maintenance expenses, depreciation, interest on loans, and return on equity.

Ancillary Services

Services provided by generators, aggregators, and other entities to system operators to maintain the real-time balance of supply and demand and ensure grid stability; includes regulation (frequency response), spinning reserve, and non-spinning reserve.

AT&C Loss

Aggregate Technical and Commercial loss — the percentage of electricity units entering the distribution system that are not billed and collected from consumers; encompasses both physical network losses and commercial losses due to theft and billing inefficiencies.

Capacity Charge

The fixed component of electricity tariff for conventional generating stations that is payable by the procurer regardless of whether electricity is scheduled from the generating station; covers depreciation, interest on loans, return on equity, and fixed operation and maintenance expenses.

Captive Generating Plant

A power plant established by a person or group of persons primarily for the purpose of generating electricity for their own use and not for sale to others, as defined in the Electricity Act, 2003 and the Electricity Rules.

Day-Ahead Market (DAM)

The electricity market segment on the Power Exchanges in which participants buy and sell standardised electricity contracts for delivery during specific 15-minute blocks on the following day, with prices determined through double-sided auction clearing.

Energy Charge

The variable component of electricity tariff for conventional generating stations that is payable by the procurer only for electricity actually scheduled and supplied; based on the normative specific fuel consumption (heat rate) and the applicable fuel price.

Grid Code (IEGC)

The Indian Electricity Grid Code — issued by CERC under Sections 73(c) and 79(1)(h) of the Electricity Act, 2003 — specifying the technical and commercial framework for the operation and use of the Inter-State Transmission System, including scheduling and despatching procedures, metering and energy accounting, and grid discipline requirements.

Long-Term Power Purchase Agreement

A power purchase agreement with a term typically of 20–25 years, entered into between a generator and a distribution utility or other buyer, and subject to approval or tariff adoption by the Appropriate Commission under Sections 62 or 63 of the EA 2003.

Merit Order Despatch

The practice of scheduling electricity generation from available generating units in ascending order of their variable generation cost (energy charge rate), ensuring that the cheapest available generation is scheduled first to minimise the total cost of electricity procurement.

Net Metering

A regulatory mechanism enabling consumers with rooftop solar or other distributed generation installations to offset their electricity consumption from the grid with the electricity they generate and export to the grid, with the net consumption (imports minus exports) billed at the applicable retail tariff.

Open Access Consumer

A consumer who sources electricity from a generator or trader of their choice and uses the transmission or distribution network of a licensee to deliver the electricity to their premises, subject to payment of applicable wheeling charges, transmission charges, cross-subsidy surcharge, and additional surcharge.

Power Exchange

A recognised entity that operates an electronic platform for buying and selling electricity through standardised contracts including the Day-Ahead Market, Term-Ahead Market, Real-Time Market, and Green Day-Ahead Market, in accordance with CERC Power Market Regulations.

Renewable Energy Certificate (REC)

A market instrument representing one megawatt-hour of electricity generated from renewable energy sources and certified under the CERC REC Regulations; RECs can be purchased by obligated entities to demonstrate compliance with Renewable Purchase Obligations without physical procurement of renewable electricity.

SAIFI

System Average Interruption Frequency Index — a reliability metric measuring the average number of interruptions experienced by each consumer in a distribution system over a specified period; used in SoP standards and performance benchmarking of distribution utilities.

SAIDI

System Average Interruption Duration Index — a reliability metric measuring the average total duration (in minutes or hours) of interruptions experienced by each consumer in a distribution system over a specified period; a key metric for assessing distribution utility reliability performance.

State Load Despatch Centre (SLDC)

A body constituted under Section 31 of the Electricity Act, 2003 responsible for the optimum scheduling and despatching of electricity within a state, exercising supervision and control over the state transmission system, and collecting and communicating information relating to the operation of the state power system.

A.3 Principal Regulatory Authorities — Quick Reference

Authority	Statutory Basis	Principal Functions	Website/Contact
Ministry of Power, Government of India	Government of India (Allocation of Business) Rules	National energy policy; legislation; international cooperation; central sector projects oversight	powermin.gov.in
Central Electricity Authority (CEA)	Electricity Act, 2003 — Part IV; Section 73	National Electricity Plan; technical standards; grid standards; data and statistics; hydroelectric advisory	cea.nic.in
Central Electricity Regulatory Commission (CERC)	Electricity Act, 2003 — Part VIII; Sections 76–81	Inter-state tariff regulation; ISTS trading licence; open access regulation; market regulation; advisory	cercind.gov.in
Appellate Tribunal for Electricity (APTEL)	Electricity Act, 2003 — Part IX; Sections 110–125	Appellate jurisdiction over all CERC and SERC orders; appeal to Supreme Court under Section 125	aptel.gov.in
Powergrid Corporation of India Ltd (CTU)	Designated under Section 38 of EA 2003	Development and operation of ISTS; non-discriminatory open access to ISTS; transmission planning	powergridindia.com
National Load Despatch Centre (NLDC) / POSOCO	Section 26 of EA 2003; CERC Grid Code	Optimum scheduling and despatching of electricity within national grid; grid security; frequency management	posoco.in
Bureau of Energy Efficiency (BEE)	Energy Conservation Act, 2001 — Section 3	Standards and labelling; energy audits; energy conservation building code; PAT scheme; carbon market	beeindia.gov.in
State Electricity Regulatory Commissions (SERCs)	Electricity Act, 2003 — Section 82; state-specific statutes	State tariff regulation; distribution licensing; open access in distribution; RPO; consumer protection	State-specific websites

CHAPTER ONE (CONTINUED)

The Orissa Reform Model & State-Level Electricity Restructuring

Corporatisation, Unbundling, Privatisation, and the First Generation of Independent Regulation

1.7 The Orissa Reform in Depth: A Template for National Reform

The Orissa electricity sector reforms of the mid-1990s deserve extended analysis because they constituted not merely a state-level regulatory experiment but a deliberate template for the national reform programme that culminated in the Electricity Act, 2003. The design of the Orissa reforms drew heavily on the United Kingdom's experience with electricity sector privatisation and restructuring under the Electricity Act, 1989, as well as on contemporaneous reform experiences in Australia (particularly Victoria and South Australia), New Zealand, and the transition economies of central and eastern Europe. The World Bank and the UK Department for International Development (DFID) provided technical assistance to the Government of Orissa in designing the reform programme, contributing to the international character of the reform framework.

The Orissa Electricity Reform Act, 1995 established the principal legal framework for the reform process. The Act mandated the corporatisation of the Orissa State Electricity Board, converting it from a statutory board governed under the Electricity (Supply) Act, 1948 into a corporate entity or group of entities governed under company law. Corporatisation was designed to achieve several objectives simultaneously: to introduce corporate governance disciplines including board accountability, financial transparency, and performance management into the management of the electricity sector; to create distinct legal entities for the generation, transmission, and distribution functions whose performance could be measured and regulated independently; to enable the privatisation of one or more of these entities without requiring fresh statutory authority; and to make the entities eligible for commercial borrowing on capital markets without the encumbrance of government guarantees.

The corporatisation of the Orissa State Electricity Board produced four successor entities: the Grid Corporation of Orissa (GRIDCO), responsible for transmission and bulk power procurement; and three distribution companies — the Central Electricity Supply Utility of Orissa (CESU), the North Eastern Electricity Supply Company of Orissa (NESCO), the Western Electricity Supply Company of Orissa (WESCO), and the Southern Electricity Supply Company of Orissa (SOUTHCO) — responsible for distribution in their respective geographical zones. The Orissa Hydro Power Corporation (OHPC) was created to hold the state's hydroelectric generating assets.

The privatisation of the distribution companies — which involved the transfer of management control to private sector operators through majority share sales — was the most radical and contested element of the Orissa reform. BSES Limited (now Reliance Infrastructure) acquired management control of CESCO (initially), and AES Corporation (a US private electricity company) acquired management control of NESCO, WESCO, and SOUTHCO through competitive bidding. The privatisation process was accompanied by intensive regulatory oversight by the Orissa Electricity Regulatory Commission, which had been established in 1996 as India's first independent electricity regulatory commission with statutory tariff-setting powers.

The outcomes of the Orissa privatisation experiment were mixed and provided important lessons that influenced the design of subsequent reform initiatives in other states and at the national level. On the positive side, the establishment of the OERC as an independent regulatory commission with credible tariff-setting authority was widely regarded as a success: the OERC demonstrated that independent electricity regulation was institutionally feasible in the Indian administrative and political environment, and that an independent commission could issue technically competent tariff orders that were respected by both the utilities and the courts. On the negative side, the distribution privatisation produced disappointing results in terms of AT&C loss reduction and service quality improvement: the private distribution companies faced severe financial constraints arising from the inherited distribution infrastructure deficiencies, the legacy of underpriced tariffs, and the challenges of operating in a high-loss environment with inadequate metering and billing systems.

The lessons drawn from the Orissa experience — particularly the lesson that regulatory independence is achievable and valuable while distribution privatisation requires very careful design and sequencing to succeed — were incorporated into the national reform design. The Electricity Act, 2003 mandated regulatory commissions for all states (the key success of the Orissa model) while leaving the question of distribution privatisation entirely to the discretion of the states (acknowledging the difficulties of the Orissa privatisation experience). This selective adoption of the Orissa model's lessons is a good example of evidence-based policy adaptation in the context of infrastructure regulatory reform.

1.8 State-Level Reform in the Late 1990s: A Comparative Survey

Following the Orissa example, several Indian states undertook electricity sector reforms during the period 1996–2002, creating the landscape of partial reform and institutional experiment into which the Electricity Act, 2003 was introduced as the comprehensive national framework. The state reform experiences varied considerably in their scope, design, and outcomes, reflecting the diversity of political conditions, electricity sector characteristics, and administrative capacities across Indian states.

Haryana was one of the first states after Orissa to undertake comprehensive electricity reform. The Haryana Electricity Reform Act, 1997 provided for the unbundling of the Haryana State Electricity Board into separate generation, transmission, and distribution entities, and established the Haryana Electricity Regulatory Commission (HERC) as an independent regulatory body. The privatisation of electricity distribution in Haryana was more cautious than in Orissa: rather than outright privatisation, the state chose to convert the distribution function into separate corporate entities (Haryana Vidyut Prasaran Nigam Limited for transmission and DHBVN and UHBVN for distribution) while retaining government ownership. HERC developed as a credible and active regulatory commission, and Haryana's experience with independent regulation was largely positive.

Andhra Pradesh undertook electricity sector reform under the Andhra Pradesh Electricity Reform Act, 1998, establishing the Andhra Pradesh Electricity Regulatory Commission (APERC) and unbundling the Andhra Pradesh State Electricity Board into corporate successors. The Andhra Pradesh reform was notable for its scale (Andhra Pradesh was one of the largest electricity sectors in the country) and for the regulatory challenges arising from the large agricultural consumer base with heavily subsidised tariffs. APERC developed an active and innovative regulatory programme, including pioneering work on multi-year tariff frameworks and regulatory treatment of agricultural subsidies.

Delhi's electricity sector underwent a distinctive reform trajectory: the privatisation of electricity distribution in the national capital under a special framework negotiated between the Delhi government and two private sector operators (BSES Delhi and Tata Power Delhi Distribution) in 2002. The Delhi privatisation was structured as a concession arrangement under which the private operators acquired the assets of the distribution companies at a negotiated price, subject to a regulatory compact with the Delhi Electricity Regulatory Commission (DERC) specifying targets for AT&C loss reduction, capital investment, and consumer service improvement. The Delhi privatisation is widely regarded as India's most successful distribution privatisation, with AT&C losses falling from approximately 55 per cent at the time of privatisation to single digits over a period of 15 years.

Gujarat, Karnataka, Uttar Pradesh, Madhya Pradesh, and Rajasthan all established State Electricity Regulatory Commissions during the period 1998–2002, either under state-level reform legislation or under the Electricity Regulatory Commissions Act, 1998. The quality and pace of regulatory development varied considerably among these commissions: some established themselves quickly as credible and active regulatory bodies, while others took longer to develop effective regulatory programmes in the face of political pressures and institutional capacity constraints. The overall picture at the time of the Electricity Act, 2003's enactment was one of significant but uneven progress in electricity regulatory reform across the country — a landscape that the Act sought to systematise and accelerate through the mandatory establishment of SERCs in all states and the comprehensive national regulatory framework of the 2003 legislation.

1.9 The Integrated Energy Policy and the Long-term View

The Planning Commission of India published its Integrated Energy Policy (IEP) in 2006, the first comprehensive national energy policy document to address the electricity, petroleum, coal, and renewable energy sectors in an integrated framework. The IEP made projections of India's long-term energy requirements under various growth scenarios and assessed the adequacy of current and planned energy supply infrastructure to meet projected demand. The IEP's projections highlighted the massive scale of investment required in electricity generation, transmission, and distribution to meet India's development aspirations, and provided the analytical foundation for the ambitious capacity addition targets of the successive Five-Year Plan periods under the Planning Commission framework.

The IEP was significant from a legal and regulatory perspective because it articulated, at the level of national policy, the framework within which the Electricity Act, 2003's regulatory institutions were expected to operate. The IEP's recommendations on tariff rationalisation, fuel supply security, renewable energy promotion, and energy efficiency improvement were reflected in subsequent iterations of the National Electricity Policy and the Tariff Policy, creating a policy linkage between the long-term integrated energy planning framework and the regulatory framework of the 2003 Act. The dissolution of the Planning Commission in 2014 and its replacement by the NITI Aayog has altered the institutional framework for integrated energy planning, though the Electricity Act, 2003's provisions for the National Electricity Plan continue to provide the statutory mechanism for long-term electricity planning.

CHAPTER TWO (CONTINUED)

Constitutional Issues in Electricity Regulation: Deeper Analysis

Fiscal Federalism, Regulatory Independence, and the Constitutional Limits of Electricity Governance

2.7 Fiscal Federalism and Electricity Subsidies

The intersection of electricity tariff regulation with the fiscal federalism provisions of the Constitution (Articles 268–293) is a matter of significant practical importance. State governments have traditionally funded electricity subsidies for agricultural and domestic consumers from their own budget resources, treating these subsidies as a legitimate expenditure of state fiscal policy. The financial burden of these subsidies has, in some states, grown to a level that threatens the fiscal sustainability of the state government itself, creating pressure for the rationalisation of subsidies without the politically unpopular act of raising electricity tariffs.

The Ujwal DISCOM Assurance Yojana (UDAY) scheme launched by the Central Government in 2015 represents one of the most significant attempts to address the intersection of fiscal federalism and electricity sector finance in post-reform India. UDAY provided for the restructuring of the accumulated debt of state distribution utilities through a mechanism of partial take-over of DISCOM debt by state governments and issuance of state government bonds, combined with an operational improvement programme requiring DISCOMs to achieve specified targets for AT&C loss reduction and cost-reflective tariff recovery. The scheme directly engaged the fiscal resources of the state governments, requiring them to formally acknowledge and absorb the contingent liability represented by their DISCOMs' accumulated losses. By the time of UDAY's implementation, the aggregate accumulated losses and debt of state DISCOMs had grown to several lakh crore rupees, representing a structural liability that threatened both the financial stability of the state governments and the ability of the DISCOMs to attract investment and credit.

The constitutional framework of Article 293, which imposes conditions on state government borrowing, has bearing on DISCOM financing in cases where state governments provide guarantees for DISCOM loans from commercial sources. Article 293(3) requires the consent of the Central Government before a state that is indebted to the Union can issue fresh guarantees or incur fresh borrowings. In states with high existing debt levels, this provision has at times constrained the ability of the state government to guarantee additional DISCOM borrowings, creating financing constraints that further strained the liquidity of the distribution utilities.

2.8 Regulatory Independence and Constitutional Standards

The concept of regulatory independence — the insulation of regulatory decision-making from political interference — is a constitutional value in the context of electricity regulation, though its constitutional basis is more implicit than explicit in the text of the Constitution. The constitutional provisions relevant to regulatory independence include: Article 14 (which requires that governmental authority, including regulatory authority, be exercised on rational and non-arbitrary grounds); the rule of law principle embedded in the Preamble and fundamental rights provisions of the Constitution (which requires that regulatory decisions be made through a fair and transparent process governed by law rather than by executive fiat); and the constitutional protection of property rights (which requires that regulatory decisions affecting the financial interests of utilities and consumers be made through a legally valid process that respects the contractual and legitimate expectations of all affected parties).

The tenure protections for the Chairperson and Members of the regulatory commissions — which prevent their removal during their term of office except through the specified procedures (including a Supreme Court inquiry in the case of the Chairperson of CERC) — are the primary institutional mechanisms for ensuring regulatory independence. These protections prevent the state government (in the case of SERCs) or the Central Government (in the case of CERC) from removing a regulator who makes an unpopular decision, thereby protecting the integrity of the regulatory decision-making process from political pressure. Courts have upheld these tenure protections as constitutionally valid exercises of Parliament's power to design regulatory institutions with appropriate independence for the discharge of their functions under the Electricity Act, 2003.

The relationship between regulatory independence and governmental direction-giving is a perennial tension in Indian administrative law. Section 107 of the Electricity Act, 2003 provides that the Appropriate Commission shall, in the exercise of its powers and discharge of its functions under the Act, be guided by such directions on questions of policy as the Central Government may give in writing from time to time. This provision is a potential qualification of regulatory independence: if the Central Government can give policy directions to CERC, and if those directions are broad enough to influence CERC's decision in specific tariff cases, the independence of tariff regulation is compromised. Courts and regulators have developed the principle that Section 107 policy directions from the Government must be truly directions on questions of policy and not directions on specific regulatory decisions in individual cases: the Government can tell CERC that renewable energy promotion is a policy priority, but cannot tell CERC how to determine the tariff of a specific renewable energy project.

CERC: Power Markets, Ancillary Services & Market Design

From Bilateral Trading to Organised Exchanges: The Evolving Indian Electricity Market Architecture

5.7 Organised Electricity Markets: Power Exchanges and Market Design

The development of organised electricity markets in India — through the establishment of power exchanges where buyers and sellers can trade standardised electricity contracts through double-sided auctions — represents one of the most significant developments in the Indian electricity sector since the enactment of the Electricity Act, 2003. Power exchanges provide the transparent, liquid, and price-efficient alternative to bilateral trading that is essential for the functioning of competitive electricity markets, and their prices serve as reference points that discipline the terms of bilateral power purchase agreements even between parties who do not directly trade on the exchange.

India's first power exchange, the Indian Energy Exchange (IEX), commenced operations in June 2008, followed by the Power Exchange India Limited (PXIL) in October 2008. Both exchanges operate under the CERC (Power Market) Regulations, which establish the regulatory framework for the recognition, operation, and oversight of power exchanges. The Regulations specify the requirements for recognition as a power exchange (including minimum net worth, governance structure, technology infrastructure, and operational standards); the market segments that exchanges may offer; the requirements for clearing and settlement of exchange-traded contracts; the obligations of participants and exchanges regarding reporting and compliance; and the powers of CERC to monitor and regulate exchange operations.

The major market segments operated by the Indian power exchanges include: the Day-Ahead Market (DAM), in which buyers and sellers submit bids for electricity delivery during specific 15-minute blocks on the following day, and market clearing prices are determined through a uniform marginal price auction; the Term-Ahead Market (TAM), which allows participants to enter into standardised contracts for electricity delivery over periods ranging from a few days to up to one year; the Real-Time Market (RTM), introduced in June 2020, which allows participants to trade electricity in near real-time (delivery 15 minutes after bid submission) in order to balance their positions close to the delivery period; and the Green Day-Ahead Market (G-DAM), introduced in 2021, which is dedicated to trading of renewable energy and allows renewable generators to participate in the day-ahead market under specific provisions designed to accommodate the variable output of wind and solar generation.

Market Coupling — the integration of the Day-Ahead Markets of IEX and PXIL into a single, integrated auction — was implemented by CERC in 2024, creating a single uniform price for DAM transactions across both exchanges. Market coupling is designed to improve market efficiency by: eliminating price differences between exchanges that arose when the same buyer and seller could face different prices on IEX and PXIL for equivalent transactions; increasing the depth and liquidity of the combined market relative to the two separate exchange markets; and reducing the potential for market power abuse by participants who could previously exploit the fragmentation between exchanges. The implementation of market coupling was a significant regulatory achievement that demonstrated CERC's capacity to manage complex market design reforms.

5.8 Ancillary Services Framework

The ancillary services framework — the regulatory and market mechanism for procuring and compensating services that maintain the real-time stability of the electricity grid beyond normal energy scheduling and despatch — is an area of active regulatory development by CERC. As India's electricity grid integrates larger volumes of variable renewable energy from wind and solar sources, the requirement for flexible ancillary services capable of responding rapidly to variations in renewable output becomes more critical for grid stability and reliability.

CERC's ancillary services framework covers three principal categories of service: Primary Response (also called droop response or under-frequency load shedding), which is the automatic near-instantaneous response of generating units to frequency deviations from the nominal 50 Hz; Secondary Reserve (also called Automatic Generation Control or AGC), which is the automatic real-time adjustment of generating unit output in response to signals from the Regional Load Despatch Centre to restore frequency to its nominal level after a primary response; and Tertiary Reserve (also called Spinning Reserve or Replacement Reserve), which involves the pre-positioning of available generating capacity that can be despatched within a short timeframe (typically 15–30 minutes) to replace capacity that has been consumed in primary and secondary response.

The commercial framework for ancillary services in India has evolved significantly since the early days of the Electricity Act, 2003 framework. The initial framework relied primarily on regulatory obligations imposed on generating units connected to the ISTS to provide ancillary services as a condition of their grid connectivity, without specific commercial compensation for the provision of these services. This framework was widely regarded as inadequate given the value of ancillary services for grid reliability and the opportunity cost of providing them. CERC has progressively developed a more market-oriented ancillary services framework under which: generators providing secondary reserve (AGC) services receive a capacity payment for their availability to provide the service and an energy payment for the activation of the service; the procurement of ancillary services is administered by the National Load Despatch Centre (NLDC) under CERC-approved procedures; and the cost of ancillary services is recovered from all users of the ISTS through the transmission tariff mechanism.

5.9 CERC and the Energy Transition: Regulatory Framework for New Technologies

CERC has been at the forefront of developing regulatory frameworks for the new technologies and market structures that are reshaping the Indian electricity sector as it transitions towards a high-penetration renewable energy future. Key regulatory innovations by CERC in this domain include the following.

Battery Energy Storage Systems (BESS): CERC has developed a regulatory framework for the connection and operation of battery energy storage systems to the ISTS, specifying the technical standards for grid connectivity, the tariff treatment of storage assets, and the market participation rules for storage in the power exchanges. The CERC (Connectivity and General Network Access) Regulations, 2022, include specific provisions for the connectivity of Energy Storage Systems, reflecting the growing importance of storage as a flexibility resource for integrating variable renewable generation. The tariff regulatory treatment of storage is complex because storage systems can be characterised both as generation assets (when discharging) and as load (when charging), and the regulatory framework must accommodate this dual character while providing appropriate revenue signals for investment in storage infrastructure.

Green Hydrogen: CERC has engaged with the regulatory questions arising from the proposed development of green hydrogen production using electricity from renewable sources. The key regulatory issues include: the framework for the supply of renewable electricity to electrolysers (whether through dedicated long-term PPAs, through open access under the GNA framework, or through captive generation arrangements); the treatment of electrolysers as large consumers for the purposes of open access charges; and the regulatory framework for any hydrogen produced and sold as a fuel or feedstock. CERC has initiated consultations on these issues and is expected to develop a comprehensive regulatory framework for green hydrogen as the technology matures and investment begins to flow.

Electric Vehicle Charging Infrastructure: The rapid growth of electric vehicle adoption in India creates regulatory questions about the framework for electric vehicle charging stations as a category of electricity consumer and potentially as a category of electricity service provider. CERC's regulatory jurisdiction is engaged in relation to the supply of electricity for EV charging stations connected to the ISTS and for vehicle-to-grid (V2G) services that could provide ancillary services to the grid from EV batteries. CERC has issued consultative papers on the regulatory framework for EV charging infrastructure and V2G services, signalling the Commission's recognition of the growing regulatory significance of this domain.

CHAPTER SIX (CONTINUED)

SERCs: Cross-Subsidy, Regulatory Capacity & Consumer Welfare

Structural Challenges, International Comparisons, and the Path to Regulatory Excellence

6.6 Cross-Subsidy Framework: Legal Principles and Regulatory Practice

Cross-subsidisation in electricity tariffs — the practice of setting tariffs for some consumer categories above the cost of supply in order to fund below-cost tariffs for other categories — is one of the most politically entrenched and legally contested features of the Indian electricity regulatory landscape. The legal framework for cross-subsidy management in the Electricity Act, 2003 reflects the tension between the economic imperative of cost-reflective tariffs and the social policy objective of affordable electricity for lower-income consumers, a tension that pervades Indian electricity regulation.

Section 61(g) of the Electricity Act, 2003 requires the Appropriate Commission to be guided by the principle "that the tariff progressively reflects the cost of supply of electricity and also, reduces and eventually eliminates cross-subsidies within the period to be specified by the Appropriate Commission." This provision embeds a legal mandate for the progressive rationalisation of cross-subsidies in electricity tariffs, though the pace of rationalisation is left to the Commission's discretion and the endpoint of "eventual elimination" is not given a specific target date. The Tariff Policy reinforces and elaborates this mandate, specifying that cross-subsidies should be reduced to within plus or minus 20 per cent of the average cost of supply for each consumer category, on a trajectory to be achieved over a specified period.

In practice, the progress of cross-subsidy rationalisation has been slow and uneven across the country. The political economy of cross-subsidy reduction is unfavourable: the beneficiaries of cross-subsidy reduction (typically industrial and commercial consumers who are currently cross-subsidising other categories) are generally more commercially sophisticated and politically influential than the beneficiaries of cross-subsidisation (agricultural and domestic consumers), but the latter are more numerous and politically vocal. State governments have typically resisted SERC orders that significantly increase tariffs for agricultural or domestic consumers, and have used the Section 65 mechanism (under which the state government can directly subsidise specified consumer categories by paying the difference between the approved tariff and the cost of supply directly to the distribution licensee) to mitigate the impact of cross-subsidy rationalisation on these consumer categories.

The Section 65 mechanism — under which the state government pays the subsidy directly to the distribution licensee rather than embedding it in the tariff structure — is conceptually superior to cross-subsidisation because it makes the cost of the subsidy visible and attributable to the state budget, promotes more accurate cost signals for electricity consumption, and reduces the financial distortion of the distribution utility's accounts. However, the implementation of Section 65 requires that the state government actually make the promised subsidy payments in full and on time, which has been a significant challenge in practice: many state governments have systematically underpaid the subsidies promised under Section 65 arrangements, creating financial stress for distribution utilities and accounting distortions in their financial statements.

6.7 SERC Regulatory Capacity: Challenges and Development

The effectiveness of State Electricity Regulatory Commissions in delivering the benefits of independent regulation — cost-reflective tariffs, improved service quality, consumer protection, and competitive market development — depends critically on the regulatory capacity of the Commissions. Regulatory capacity encompasses: the technical and analytical expertise of Commission staff; the quality of the evidentiary record developed in regulatory proceedings; the Commission's ability to process and analyse complex financial and technical submissions from regulated entities; the Commission's institutional independence from governmental and commercial pressures;

and the Commission's capacity for consistent and predictable decision-making that creates regulatory certainty for investors and utilities.

Significant variation in regulatory capacity exists among the 29 SERCs currently operating across India. Well-established and well-resourced Commissions such as MERC (Maharashtra), GERC (Gujarat), DERC (Delhi), and KERC (Karnataka) have developed substantial internal expertise and have issued sophisticated regulatory orders that compare favourably with the output of mature regulatory commissions in other countries. Less well-resourced Commissions, particularly in smaller states and newly established jurisdictions, have faced challenges including: difficulty attracting and retaining qualified technical and legal staff given civil service salary structures that cannot compete with private sector alternatives; inadequate analytical infrastructure including data management systems and financial modelling tools; backlogs in processing tariff petitions and other applications arising from limited staff capacity; and vulnerability to political pressure in states with weak traditions of administrative independence.

Several initiatives have been undertaken to strengthen SERC regulatory capacity on a sector-wide basis. The Forum of Regulators (FoR), constituted under Section 166 of the Electricity Act, 2003 as an association of CERC and all SERCs, has been an important forum for inter-commission coordination, learning, and the development of common regulatory frameworks. The FoR has issued model regulations and guidelines covering matters including multi-year tariff principles, consumer protection standards, open access, renewable energy, and smart metering, which individual SERCs can adopt with appropriate state-specific modifications. This standard-setting function of the FoR has been valuable in promoting regulatory convergence across the country and reducing the transaction costs of doing business in the electricity sector across multiple states.

CHAPTER NINE (CONTINUED)

Captive Power, Energy Trading & Market Instruments

Legal Framework for Captive Generation, Electricity Trading, and Emerging Market Structures

9.7 Captive Power Plants: Legal Framework under the Electricity Act, 2003

The legal framework for captive power plants — generating stations established primarily to supply electricity for the own use of the captive user or users — is governed by Section 9 of the Electricity Act, 2003 and the Electricity Rules, 2005. The captive generation framework enables large industrial consumers, commercial establishments, and special economic zones to establish and operate their own generating capacity to reduce their dependence on grid electricity supply and to achieve greater electricity cost certainty and reliability. The captive generation framework has been an important driver of private sector investment in electricity generation in India, particularly for industrial consumers in sectors where electricity is a significant cost input.

The distinction between "captive" generation (which does not require a generation licence under Section 7) and generation for commercial sale (which may attract licensing requirements for trading) depends on whether the consumption of the generating unit's output satisfies the conditions specified in the Electricity Rules, 2005 for the treatment of a generating plant as a captive generating plant. The Rules specify that a generating plant shall qualify as a captive generating plant if: at least 26 per cent of the equity shares in the generating plant are held by the captive user(s); and at least 51 per cent of the electricity generated by the plant in any year is consumed for the captive use of the captive user(s).

These two conditions — the minimum 26 per cent equity holding by captive users and the minimum 51 per cent captive consumption — have been the subject of extensive regulatory and judicial controversy. The equity holding condition has been challenged on the grounds that it is an unduly rigid requirement that may prevent captive generation arrangements structured as project finance transactions (in which the captive user does not wish to hold equity in the project company directly but prefers to off-take electricity under a long-term contract). The consumption condition has been challenged in cases where the captive consumption in a particular year falls below 51 per cent due to operational factors (such as plant maintenance or reduced industrial production at the captive user's facilities) beyond the captive user's control.

The Supreme Court has addressed the conditions for captive generation in a significant number of decisions, establishing the principle that the conditions specified in the Electricity Rules must be satisfied on an ongoing annual basis throughout the useful life of the generating plant, and that failure to satisfy either condition in any year results in the plant losing its captive status for that year with attendant regulatory consequences (including the possible requirement to obtain a generation licence and to sell the surplus electricity through specified channels). The Court has also addressed the question of what counts as "captive use" in the context of group captive arrangements, in which a number of unrelated industrial consumers come together to jointly establish a captive power plant, holding equity shares in proportion to their expected electricity off-take. Group captive arrangements have been recognised as legally valid under the Electricity Act framework, subject to satisfaction of the conditions in the Rules.

9.8 Electricity Trading: Legal Framework, Categories, and Market Role

Electricity trading — the purchase of electricity for resale — occupies a distinct category in the electricity sector legal framework, separate from generation (which is de-licensed), transmission (which is regulated as a natural monopoly through licensing), and distribution (which is licensed as a regulated monopoly within a geographical area of supply). The trading licence requirement under Section 12 of the Electricity Act, 2003, and the framework of CERC's trading licence regulations, creates a regulated market for electricity intermediaries who facilitate the matching of buyers and sellers across the bilateral market segment of the Indian electricity market.

Electricity traders serve several important functions in the Indian electricity market. They reduce the search and transaction costs for generators and distribution utilities seeking to enter into bilateral power purchase agreements, particularly for short-term and medium-term supply requirements that do not justify the administrative cost of a formal competitive tender. They provide liquidity in the market by standing between buyers and sellers and taking on counterparty credit risk management functions. They enable geographic arbitrage by purchasing electricity in surplus regions and selling it in deficit regions, facilitating the inter-state power flows that are necessary for efficient utilisation of the electricity generation capacity distributed unevenly across the country. And they provide market price signals that help inform the investment and operational decisions of generators and distribution utilities.

The principal categories of electricity trading in India include: long-term bilateral trading under PPAs between generators and distribution utilities (which typically involve the trading licensee as a mediator rather than a principal in the transaction); medium-term bilateral trading for supply periods of 90 days to three years (in which the trading licensee typically acts as principal, purchasing electricity from a generator and re-selling to a distribution utility or large consumer); short-term bilateral trading for supply periods up to 90 days (which constitutes the highest-volume segment of the trading licence segment); and cross-border electricity trading with Nepal, Bhutan, Bangladesh, and Myanmar under the framework of bilateral cross-border electricity trading agreements facilitated by CERC's cross-border trading guidelines.

The cross-border electricity trading framework developed by CERC, consistent with India's broader energy diplomacy goals in the South Asian region, enables electricity to be traded across India's international borders under a regulatory framework that addresses issues of: tariff regulation for power flowing through India's transmission system to and from neighbouring countries; settlement of transmission charges for cross-border transactions; the treatment of cross-border electricity supply as "export" or "import" for the purposes of India's customs and foreign exchange regulations; and the regulatory framework applicable to bilateral energy agreements between India and its neighbours. Cross-border electricity trading has grown significantly in recent years, with significant hydroelectric power imports from Bhutan under long-term agreements and increasing two-way trade with Bangladesh and Nepal.

9.9 The Power System Operation Framework

The power system operation framework — the regulatory and technical arrangements governing the real-time balancing of supply and demand in the electricity grid — is a critical dimension of the legal framework for electricity in India. The Power System Operation Corporation of India Limited (POSOCO), designated as the National Load Despatch Centre (NLDC) under Section 26 of the Act, and the five Regional Load Despatch Centres (RLDCs) and individual State Load Despatch Centres (SLDCs) operate the scheduling and despatching framework that co-ordinates the real-time operation of the electricity system across the country.

The scheduling and despatching framework, governed by the Indian Electricity Grid Code (IEGC) issued by CERC and by the respective state grid codes issued by the SERCs, operates on a 15-minute time block basis: generators submit their generation schedules for each 15-minute block of the following day to the relevant Load Despatch Centre by the specified submission deadline, the RLDC/SLDC aggregates all schedules and determines the Declared Net Transfer Capability (NTC) — the amount of power that can safely be transferred between regions given the current condition of the transmission network — and issues revised schedules to generators if necessary to manage transmission constraints. The actual generation in each 15-minute block is metered by special energy meters installed at the generator bus-bars and at the delivery points of distribution utilities, and the deviation of actual generation or consumption from the scheduled quantity is settled through the Deviation Settlement Mechanism (DSM), which penalises entities that deviate from their schedules at times of grid stress (low frequency) and rewards entities that provide counter-deviation support.

The DSM mechanism — which replaced the earlier Unscheduled Interchange (UI) mechanism from 2016 onward — is designed to create financial incentives for grid discipline: entities that draw more power from the grid than scheduled when the grid is stressed (i.e., frequency is below nominal) pay high DSM charges, while entities that inject more power than scheduled at such times receive high DSM payments. This price signal encourages entities with flexible generation or demand to voluntarily adjust their behaviour in ways that support grid frequency stability, reducing the need for the system operator to rely on mandatory load shedding to maintain frequency within safe bounds.

Sector Governance: Challenges, Comparative Experience & Outlook

Structural Reform Challenges, International Regulatory Benchmarks, and India's Energy Transition

10.6 Governance Challenges in the Distribution Segment

Despite the significant regulatory and institutional reforms of the post-EA 2003 period, the distribution segment of the Indian electricity sector remains characterised by severe financial stress, high AT&C losses in many states, inadequate quality of supply, and persistent cross-subsidy distortions. These structural challenges represent the most significant unresolved governance problem in the Indian electricity sector, and their resolution is essential for the achievement of the electricity access, reliability, and affordability goals set out in the national electricity policy framework.

The financial stress of state distribution utilities — the aggregate unpaid dues of which to generating companies and transmission licensees have grown to several lakh crore rupees in recent years — has systemic consequences beyond the distribution segment itself. Unpaid dues from DISCOMs to generating companies have impaired the liquidity of the generation segment, with some generators facing revenue shortfalls that threaten their debt servicing capacity and have caused several private thermal power projects to be classified as stressed assets by lenders. The Late Payment Surcharge Rules, 2022, introduced by the Ministry of Power under the Electricity Act, 2003, established a regulatory framework for addressing DISCOM payment defaults to generating companies, requiring state governments to provide payment security in the form of letters of credit as a condition of generators being obligated to supply electricity to defaulting DISCOMs. This regulatory intervention represents a significant escalation of the Central Government's involvement in managing the financial consequences of DISCOM payment behaviour.

The Revamped Distribution Sector Scheme (RDSS), launched by the Central Government in 2021 with a substantial financial outlay, is the most recent in a series of centrally-sponsored schemes for distribution infrastructure upgradation and operational improvement. RDSS provides financial assistance to distribution utilities for: the installation of prepaid smart meters for domestic, industrial, and commercial consumers; system strengthening works including distribution transformer upgradation, feeder separation, and high-voltage distribution system installation; and the upgradation of IT and data management infrastructure for billing, metering, and revenue collection. RDSS ties the release of financial assistance to the achievement of specified milestones including operational efficiency improvement and reduction of aggregate technical and commercial losses, attempting to create an incentive structure that encourages genuine performance improvement rather than merely absorbing central funds without demonstrable impact.

10.7 International Experience: Comparative Regulatory Frameworks

A comparative perspective on international electricity regulatory experience can provide useful insights for the ongoing development of India's electricity regulatory framework. The regulatory systems of several countries offer relevant points of comparison.

The United Kingdom's electricity regulatory system, which underwent privatisation and restructuring beginning with the Electricity Act, 1989 and the privatisation of the Central Electricity Generating Board, provides the most direct historical antecedent for several elements of the Indian reform framework. The UK experience demonstrated that: the unbundling of the vertically integrated electricity utility into separate generation, transmission, and distribution entities could be achieved without significant disruption to supply security; an independent regulatory body (Ofgem, combining the earlier Offer and Ofgas) with robust legal powers and high technical capacity could successfully regulate the natural monopoly segments of the privatised electricity industry; the development of competitive generation and retail electricity supply markets could produce efficiency gains and consumer choice without compromising supply security; and the introduction of a capacity market mechanism could address the investment adequacy concerns that arise in energy-only markets where the energy price alone may not provide sufficient signals for investment in new generation capacity. India has drawn on the UK experience in designing several elements of its electricity regulatory framework, including the open access framework, the competitive bidding framework, and the discussion of capacity market mechanisms.

Australia's National Electricity Market (NEM), which operates across five states and the Australian Capital Territory, provides an example of a regionally integrated electricity market with a common regulatory framework and a competitive market structure. The Australian Energy Market Operator (AEMO) performs functions analogous to those of India's National Load Despatch Centre and also serves as the independent system operator for the NEM. The Australian Energy Regulator (AER) regulates the network segments of the NEM on a consistent national basis, providing a model of regulatory consolidation that contrasts with India's division of regulatory authority between CERC (for inter-state matters) and the SERCs (for intra-state matters). The Australian experience of managing the integration of very high penetrations of variable renewable generation (in 2023, South Australia achieved periods of 100 per cent renewable electricity in its local grid) provides potentially relevant insights for India's own renewable energy integration challenge.

The electricity regulatory systems of the European Union, operating under the common framework of the EU Electricity Directive and associated regulations, provide examples of the coordination mechanisms required to manage electricity markets across multiple national regulatory jurisdictions with different fuel mixes, demand profiles, and regulatory traditions. The EU's cross-border transmission network regulation, the Market Coupling mechanism that integrates the day-ahead electricity markets of most EU member states, and the framework for the security of electricity supply provide models for transnational electricity market integration that may be relevant as India develops its regional electricity cooperation initiatives with South Asian neighbours under the South Asian Association for Regional Cooperation (SAARC) energy framework.

10.8 Energy Transition: Legal and Regulatory Implications

India's commitment to achieving 500 GW of installed non-fossil fuel capacity by 2030 and net zero carbon emissions by 2070, announced at COP26 in Glasgow in 2021, has profound implications for the legal and regulatory framework of the electricity sector. The scale of the renewable energy expansion required — representing an increase from approximately 180 GW of installed renewable capacity in 2023 to 500 GW by 2030, implying an addition of over 45 GW per year on average — requires: a regulatory framework for the rapid approvals and connection of large volumes of new renewable capacity; a transmission network expansion programme capable of delivering the output of this capacity to load centres across the country; an energy storage framework to manage the variability of renewable output at the required scale; and a comprehensive programme of demand-side flexibility to match the pattern of electricity consumption more closely to the pattern of variable renewable generation.

The legal framework for renewable energy in India extends beyond the Electricity Act, 2003 to encompass a range of additional legislative and regulatory instruments. The Environment Protection Act, 1986 and its associated clearance regulations govern the environmental assessment and approval of large renewable energy projects, including the cumulative environmental impact assessment required for solar and wind parks occupying large areas of land. The Forest Conservation Act, 1980 governs the diversion of forest land for energy infrastructure, including transmission lines and renewable energy projects. The Land Acquisition Act, 2013 establishes the framework for the compulsory acquisition of private land for electricity infrastructure, including the enhanced compensation requirements and social impact assessment obligations that make large infrastructure projects more costly and time-consuming than they were under the predecessor legislation. The Right to Fair Compensation and Transparency in Land Acquisition, Rehabilitation and Resettlement Act, 2013 has had a significant impact on the economics and timelines of electricity infrastructure development, and has necessitated careful project design and stakeholder engagement to manage land acquisition risks in renewable energy and transmission projects.

The Energy Conservation (Amendment) Act, 2022, amending the Energy Conservation Act, 2001, introduces the Carbon Credit Trading Scheme (CCTS) as India's first domestic carbon market. The CCTS creates tradable carbon credits for entities that reduce their greenhouse gas emissions below specified baselines, and obligates certain high-emission industries to participate in the scheme. The intersection of the CCTS with the electricity sector regulatory framework is significant: electricity generation from fossil fuels generates greenhouse gas emissions subject to the CCTS, while electricity generation from renewable sources creates carbon credits; and the relative economics of fossil and renewable generation are affected by the carbon credit price, which in turn influences the merit order of electricity generation and the economic case for new renewable investment. The regulatory framework for the CCTS, including the specification of the sector-specific baselines, the monitoring and verification requirements, and the trading rules, is being developed by the Bureau of Energy Efficiency (BEE) in coordination with the Ministry of Power and the Ministry of Environment, Forest and Climate Change.

CHAPTER THREE (EXTENDED ANALYSIS)

Detailed Statutory Analysis: Parts V, VI, VII, and X

Distribution, Trading, Metering, Offences, Theft, and Transitional Provisions

3.7 Part VI — Trading in Electricity (Sections 52–64)

Trading in electricity, defined as the purchase of electricity for resale, is a regulated activity under the Electricity Act, 2003 that requires a licence from the Appropriate Commission. Part VI of the Act, comprising Sections 52 to 64, establishes the legal framework for electricity trading, covering the licensing requirement, the conditions of trading licences, the obligations of trading licensees, and the regulatory oversight of trading activities. The inclusion of electricity trading within the licensing framework, while generation is de-licensed, reflects the different risk profiles of the two activities: generation produces electricity that is a physical commodity subject to technical standards and grid connectivity requirements, while trading involves the purchase and resale of a financial claim on electricity, which can be used to facilitate arbitrage and speculation as well as genuine supply transactions.

CERC's framework for electricity trading divides licensees into two categories based on their financial capacity and trading volume. The Unrestricted Trading Licence (formerly called Category I) authorises the holder to trade in electricity without any volume ceiling, subject to the licensee maintaining a minimum net worth of Rs. 50 crore or such other amount as may be specified by CERC from time to time. The Restricted Trading Licence (formerly called Category II) imposes a ceiling on the volume of electricity the licensee may trade in any financial year (currently Rs. 1000 MUs or such limit as CERC may specify), and requires the licensee to maintain a lower minimum net worth of Rs. 1 crore or such amount as CERC may specify. The differentiation between the two licence categories reflects the greater financial exposure and systemic risk associated with high-volume trading, which requires commensurately higher financial capacity to ensure that the licensee can meet its financial obligations to counterparties even in adverse market conditions.

CERC has also issued a detailed Code of Conduct for trading licensees as part of its regulatory framework. The Code specifies the obligations of trading licensees in their dealings with buyers and sellers, including: the requirement to disclose the terms and conditions of trading arrangements including the margin earned by the trader on any transaction; the requirement to maintain detailed records of all transactions and to submit quarterly reports to CERC; the prohibition on trading licensees engaging in anti-competitive conduct including market manipulation, artificial withholding of electricity, and deceptive practices; the requirement to maintain appropriate risk management systems given the financial exposures associated with electricity trading; and the obligation to comply with CERC's directions on the conduct of the trading business.

3.8 Part VII — Metering (Sections 55–64)

The metering provisions of the Electricity Act, 2003 reflect the legislature's recognition that accurate and tamper-resistant metering is the foundation of fair and efficient electricity markets and consumer billing. Without reliable metering, the determination of tariffs, the settlement of open access transactions, the computation of AT&C losses, the billing of consumers, and the detection of electricity theft are all compromised. The Act therefore imposes a comprehensive legal obligation of metering, covers all supply arrangements without exception, and vests the Commission with authority to specify metering standards and to direct the replacement of inadequate meters.

Section 55(1) of the Electricity Act, 2003 provides that no licensee shall supply electricity, after the expiry of two years from the appointed date, except through installation of a correct meter conforming to the specifications laid down by the relevant authority. This provision establishes a universal metering obligation for all licensed electricity supply, applicable without exception to domestic, commercial, industrial, and agricultural consumers alike. The universal metering obligation was a significant departure from the practice prevailing at the time of the Act's enactment, under which large numbers of agricultural consumers in many states were supplied electricity on an unmetered flat-rate basis — a practice that made it impossible to determine the actual electricity consumption of agricultural pumps, obscured the actual distribution losses in rural networks, and facilitated theft through the misclassification of commercial or industrial loads as agricultural uses.

The CERC and SERC metering regulations specify the technical standards applicable to metering equipment used in different supply contexts, the maximum permissible error in measurement, the mandatory testing and sealing requirements for meters, the obligations of licensees in relation to the periodic testing and replacement of meters, and the rights of consumers to have their meters tested independently. The development and deployment of smart meters — meters with two-way digital communication capabilities that can provide near real-time consumption data, support pre-payment billing, enable time-of-use tariffs, and detect tampered conditions automatically — is a priority of the Central Government's RDSS scheme and is expected to transform the metering and billing landscape for electricity consumers in India over the coming decade.

3.9 Part X — Electricity Theft and Enforcement (Sections 126–135)

The offences and penalty provisions of the Electricity Act, 2003, concentrated in Part X, reflect the legislature's determination to address electricity theft — one of the most economically significant and entrenched problems in the Indian electricity sector — with a comprehensive and strictly enforced legal framework. Electricity theft in India, encompassing the direct abstraction of electricity without a meter, the tampering of meters to undercount consumption, the creation of unauthorised connections, and the corruption of officials responsible for meter reading and billing, represents a loss of billions of rupees per year to the electricity sector and contributes directly to the financial stress of distribution utilities.

Section 126 of the Act provides for the assessment of electricity charges in cases of "un-authorised use of electricity," defined as the use of electricity by any means other than authorised metered supply, or the use of electricity through a tampered meter, or the use of electricity at a supply voltage or current other than that authorised by the connection. Where an officer of the distribution licensee finds evidence of unauthorised use of electricity, Section 126 authorises the officer to assess the quantity of electricity that has been abstracted or misused and to raise a provisional assessment notice on the consumer for the estimated charges. The consumer has an opportunity to object to the provisional assessment and to seek a hearing before the Assessing Officer, whose determination is appealable to the Commission. The elaborate procedural framework of Section 126 was designed to balance the legitimate interest of the distribution licensee in recovering the financial losses caused by theft with the consumer's interest in procedural fairness and the prevention of arbitrary or extortionate assessment practices.

Section 135 of the Act creates the criminal offence of electricity theft, defined broadly to cover any person who: dishonestly abstracts, consumes, or uses any energy; connects any wires or apparatus for the purpose of abstracting, consuming, or using energy without authority from the licensee; tempers or alters any meter, measuring or testing apparatus; or dishonestly uses energy with the knowledge that alterations have been made in any meter. Section 135 provides for punishment of imprisonment for a term which may extend to three years, or with a fine, or with both, for a first offence; and imprisonment for a term not less than six months and extendable to five years for repeat offences. The provision of minimum imprisonment for repeat offenders reflects the legislature's intention that habitual electricity theft be treated as a serious offence subject to substantial criminal penalties.

The Special Courts established under Section 153 of the Electricity Act, 2003 have exclusive jurisdiction over offences under the Act, including electricity theft cases. The establishment of dedicated courts with electricity sector jurisdiction was intended to ensure that electricity theft cases are tried expeditiously by judges familiar with the technical and commercial dimensions of electricity offences, reducing the delays that had characterised the handling of electricity theft cases in the regular criminal courts. The fast track character of the Special Courts is emphasised by the provisions of Section 154, which require the Special Court to endeavour to decide electricity offences as expeditiously as possible, and to complete the trial of an offence within a period of two years from the date of filing of the complaint.

The legal challenge in electricity theft enforcement lies not in the substantive provisions of the Act — which are comprehensive and stringent — but in the practical difficulties of detection, evidence gathering, and prosecution. Distribution utilities have invested significantly in anti-theft technology including: smart meters with tamper detection capabilities that generate automatic alerts when attempts are made to interfere with the meter; drone surveillance of distribution networks for the detection of unauthorised connections; artificial intelligence-based data analytics to identify consumption patterns that are inconsistent with the registered load and supply arrangements of specific connections; and specialised anti-theft squads trained in the legal requirements for gathering admissible evidence in electricity theft cases. The effectiveness of anti-theft programmes has improved significantly in recent years in states with strong institutional commitment to AT&C loss reduction, though enforcement challenges persist in rural areas and in contexts of weak administrative capacity.

3.10 Transitional Provisions: Sections 172–185

The transitional provisions of the Electricity Act, 2003, concentrated in Sections 172–185, address the practical challenges of transitioning from the predecessor legislative framework to the new statutory architecture. These provisions were essential for ensuring the legal continuity of the electricity sector during the transition period and for managing the significant institutional, contractual, and regulatory changes that the new Act entailed.

Section 172 provides for the repeal of the Indian Electricity Act, 1910; the Electricity (Supply) Act, 1948; and the Electricity Regulatory Commissions Act, 1998, with effect from the appointed date of the 2003 Act. The repeal of these three statutes, which together constituted the legislative framework for the electricity sector since the colonial period, marked the definitive end of the old legal order and the commencement of the new. Section 172 is accompanied by a savings clause that preserves the legal validity of anything done or action taken under the repealed Acts before their repeal, including: licences and permissions granted; tariff orders made; generation assets developed and operational; and pending proceedings before the regulatory authorities. Without these savings provisions, the repeal of the predecessor Acts could have created a legal vacuum affecting the ongoing operations of virtually every entity in the electricity sector.

Section 173 provides for the continuity of the State Electricity Boards existing at the appointed date: they shall continue to function until they are reorganised, restructured, or dissolved in accordance with the provisions of the 2003 Act. This provision was critical for ensuring that the SEBs — which at the time of the Act's commencement continued to serve as the primary distribution utilities in most Indian states — could continue their operations without interruption while the states undertook the corporate restructuring and transfer of assets and liabilities to successor entities required by the new legislative framework. The restructuring of the SEBs into multiple corporate successor entities was a complex and time-consuming process that took several years in most states, and the transitional provision of Section 173 ensured that this process could proceed in an orderly manner without disrupting electricity supply.

CHAPTER FOUR (EXTENDED ANALYSIS)

CEA: National Grid Planning & Technical Standard-Setting

From Regional Grids to a Synchronous National Network: Planning, Coordination, and Engineering Standards

4.5 National Grid Development: The CEA's Planning Role

The development of the Indian national electricity grid — from a collection of isolated state and regional grids in the early post-independence period to the synchronous national grid that was achieved with the interconnection of the Southern Regional Grid in January 2014 — is one of the most significant engineering and institutional achievements in the Indian electricity sector's history. The CEA played a central role in planning, coordinating, and facilitating this development over many decades, providing the technical analysis and national perspective necessary to guide investment in Inter-State Transmission System infrastructure across what are now the five regional grids comprising the national grid.

The transition from isolated regional grids to a synchronous national grid required not only the physical construction of high-voltage direct current (HVDC) and high-voltage alternating current (HVAC) inter-regional transmission links but also the development of common technical standards, protection systems, communication protocols, and operational procedures across the five regional grids. The CEA's grid standards under Section 73(c) were the technical foundation for this harmonisation process: by specifying common standards for system frequency, voltage, protection relay settings, and operating procedures, the CEA enabled the five regional grids to eventually operate as a single synchronous alternating current system.

The five high-voltage direct current (HVDC) bipole links developed to connect the Southern Regional Grid to the rest of the country — using HVDC technology because the Southern Grid operated at a different nominal frequency from the other four regions for much of its history — were among the most technically complex electricity infrastructure projects ever undertaken in India. The CEA's technical oversight and advisory role in relation to these projects, including the review of the technical specifications for the HVDC converter stations and the transmission lines, was crucial for ensuring their successful development and commissioning. The commissioning of the HVDC links and the synchronisation of the Southern Grid with the national grid in 2014 created the conditions for the development of a truly national electricity market in which power can flow freely from any point of generation to any point of consumption subject only to the constraints of available transmission capacity.

4.6 CEA Technical Standards: Structure and Content

The CEA's technical standards documents constitute a comprehensive framework of engineering requirements for the construction, installation, and operation of electrical plants and lines in India. The standards are issued by the CEA under the authority of Section 73(b) of the Act and have the legal character of binding technical regulations enforceable through the Act's enforcement provisions. Non-compliance with CEA technical standards exposes the defaulting entity to regulatory consequences including directions to rectify the non-compliance and, in cases of serious non-compliance that threatens safety, potentially the suspension of the entity's authorisation to connect to the electricity grid.

The principal CEA technical standards documents include: the Technical Standards for Construction of Electrical Plants and Electric Lines (specifying design, materials, equipment specifications, and construction practices for major categories of generation and transmission assets); the Technical Standards for Connectivity to the Grid (specifying the technical requirements that generating stations and Energy Storage Systems must satisfy to be eligible for connection to the electricity grid, including requirements for governor response, reactive power capability, protection relay settings, and communication interfaces); the Measures Relating to Safety and Electric Supply

Regulations (specifying safety requirements for electrical installations at all voltage levels, from the high-voltage transmission system down to the low-voltage consumer connections); and the Technical Standards for Smart Electricity Meters (specifying the technical requirements for the smart meters being deployed under the RDSS scheme, including communication protocol requirements, accuracy standards, tamper detection capabilities, and cyber security requirements).

The CEA updates its technical standards periodically to reflect advances in electrical engineering practice, changes in the characteristics of the electricity grid arising from the increasing penetration of variable renewable generation and inverter-based resources, and lessons from the operation of the electricity system including from grid disturbance events and equipment failures. The process of standard updating involves consultation with industry stakeholders, technical experts, and the regulatory commissions, and the CEA's draft updated standards are published for public comment before finalisation. This consultative process ensures that the CEA's standards reflect the current state of the art in electrical engineering while remaining practically implementable given the equipment and infrastructure that is commercially available in the Indian and international market.

4.7 Interaction between CEA, CERC, and SERCs: Coordination Mechanisms

The institutional framework of the Electricity Act, 2003 creates multiple points of interaction and coordination between the CEA and the regulatory commissions. These coordination mechanisms are essential for ensuring that the technical advice of the CEA is reflected in the regulatory framework established by CERC and the SERCs, and that the regulatory framework in turn provides appropriate incentives for the development of the electricity system in the directions recommended by the CEA's national planning framework.

The most important formal coordination mechanism is the provision in Section 3(3) of the Act requiring the CEA to prepare the National Electricity Plan in consultation with the state governments, the utilities, and the Appropriate Commissions. This requirement ensures that the commissions have an opportunity to provide input into the national electricity planning process, and that the CEA's plan reflects the regulatory constraints and objectives of the commissions rather than being developed in isolation from the regulatory framework. Similarly, the provision in Section 3(4) requiring the Central Electricity Authority to prepare the National Electricity Plan "in accordance with the National Electricity Policy" creates a coordination linkage between the CEA's planning function and the policy framework set by the Central Government in consultation with the state governments and the CEA itself.

Informal coordination between the CEA and the commissions occurs through a range of mechanisms including: joint participation in workshops and technical seminars on electricity sector issues; mutual consultation on major regulatory proceedings where the CEA's technical analysis is relevant to the Commission's decision; and the secondment of CEA technical staff to assist the commissions in specific technical matters where the Commission's internal technical capacity requires supplementation. The Forum of Regulators, constituted under Section 166 of the Act, provides a formal forum in which CERC and all SERCs can coordinate on common regulatory issues; the CEA participates in FoR activities as an expert technical body, providing technical input to the regulatory coordination process.

CHAPTER SEVEN (EXTENDED ANALYSIS)

APTEL: Jurisprudential Analysis & Procedural Framework

Key Legal Principles, Procedural Practice, and APTEL's Role in Electricity Regulatory Development

7.8 Grounds of Appeal before APTEL: Legal Principles

The grounds on which an appeal to APTEL may be maintained are not exhaustively specified in the Electricity Act, 2003; the Act simply provides that any person aggrieved by a Commission order may appeal without specifying the grounds on which such an appeal may be based. In practice, APTEL has entertained appeals on the following principal categories of grounds, consistent with the general principles of administrative law applicable to the review of quasi-judicial decisions.

The most fundamental ground of appeal is the ground of jurisdiction — that the Commission that made the order was not the Appropriate Commission for the matter in question, and therefore lacked the statutory authority to make the order. Jurisdictional challenges before APTEL typically involve the inter-commission boundary between CERC and the SERCs, determined by the application of the Section 2(4) definition of "Appropriate Commission." APTEL has addressed a large number of jurisdictional challenges and has developed a principled jurisprudence on the application of the inter-state trade or commerce test to specific situations, providing regulatory clarity on the respective jurisdictions of CERC and the SERCs in a range of commercially important contexts.

The second major category of grounds is the ground of statutory interpretation — that the Commission has misinterpreted a provision of the Electricity Act, 2003, the regulations made thereunder, or any other applicable law in making its order. Statutory interpretation appeals are common in electricity regulatory litigation because the EA 2003 and its associated regulations contain many provisions that are susceptible to more than one plausible interpretation, and the financial consequences of different interpretations can be very significant for the parties. APTEL approaches questions of statutory interpretation using the standard tools of purposive interpretation, the mischief rule, and the principle that ambiguous provisions should be interpreted in a manner consistent with the overall scheme and object of the Act.

The third major category is the ground of procedural unreasonableness or breach of natural justice — that the Commission failed to follow the procedure prescribed by law or by its own regulations, or that the Commission made its order without giving the appellant a fair opportunity to be heard, or that the Commission made its order without considering relevant evidence submitted by the appellant. Procedural grounds of appeal are taken seriously by APTEL because the quasi-judicial character of Commission proceedings requires compliance with the principles of natural justice, including the right to notice, the right to be heard, the right to have one's submissions considered, and the right to a reasoned decision. Where a Commission has materially breached these procedural requirements, APTEL will typically set aside the order and remand the matter to the Commission for fresh consideration with proper procedural compliance.

The fourth major category is the ground of irrationality or perversity — that the Commission's factual or technical findings are so clearly unsupported by the evidence on the record as to be irrational or perverse. APTEL approaches factual and technical review with appropriate deference to the Commission's expertise: APTEL will not substitute its own technical judgment for that of the Commission simply because it might have reached a different conclusion on the technical evidence. However, APTEL will intervene when the Commission's technical conclusions are plainly contradicted by the evidence, when the Commission has failed to consider relevant technical evidence, or when the Commission's conclusions rest on a demonstrably incorrect technical premise.

7.9 APTEL and the Development of Electricity Law: A Regulatory Legacy

Over the two decades since the commencement of the Electricity Act, 2003, APTEL has developed a substantial and authoritative body of electricity law through its decisions on appeals from Commission orders. This jurisprudential legacy is an important part of the legal infrastructure of the Indian electricity sector, providing regulatory certainty, predictability, and legal guidance on the many difficult questions of statutory interpretation and regulatory principle that arise in the governance of a complex industry.

The regulatory principles established through APTEL's jurisprudence cover virtually every domain of electricity regulation under the EA 2003 framework. In the tariff domain, APTEL has established principles governing: the methodology for determining the capital cost of generating stations and transmission assets eligible for tariff recovery; the normative parameters applicable to different categories of generating plant; the treatment of change-in-law events in cost-based and competitive tariff determinations; the principles for the determination of transmission charges and the allocation of transmission costs among different users of the transmission system; and the framework for multi-year tariff determination and annual true-up adjustments. In the open access domain, APTEL has established principles governing: the calculation of cross-subsidy surcharges and additional surcharges; the conditions under which distribution licensees may deny or curtail open access; the non-discriminatory treatment requirements for open access users; and the rights of consumers who have invested in captive and group captive generation to access the distribution network for wheeling purposes.

APTEL's decisions on jurisdictional matters have been particularly significant in delineating the respective roles of CERC and the SERCs in the electricity regulatory system. A consistent body of APTEL precedent has clarified that: the jurisdiction of CERC is attracted by the inter-state character of the electricity transaction or the facility being regulated, not merely by the physical location of the infrastructure involved; the SERC has exclusive jurisdiction over the tariff for electricity sold to distribution consumers within the state from generating stations connected to the state transmission system, even if the generating company has other transactions that attract CERC jurisdiction; and the jurisdiction of the SERC over intra-state transmission is not affected by the fact that power from an inter-state generating station may flow through the intra-state transmission system, since the regulatory jurisdiction over the transmission facility is determined by the nature of the facility itself rather than the origin of the power flowing through it.

APTEL has also played an important role in developing the procedural norms applicable to Commission proceedings. APTEL has consistently held that the principles of natural justice — particularly the principles of audi alteram partem (hear the other side) and nemo judex in causa sua (no one should be a judge in their own cause) — apply with full force to proceedings before the regulatory commissions, and that departures from these principles constitute grounds for the setting aside of Commission orders. This insistence on procedural fairness has been an important influence on the conduct of regulatory proceedings before CERC and the SERCs, encouraging the commissions to adopt transparent and participatory procedures that give all affected parties a meaningful opportunity to present their case and challenge the evidence and arguments of opposing parties.

7.10 The Relationship between APTEL and the Forum of Regulators

The Forum of Regulators (FoR), constituted under Section 166 of the Electricity Act, 2003, provides a coordination mechanism for CERC and all SERCs on common regulatory issues of national significance. The FoR is chaired by the Chairperson of CERC and its membership comprises the Chairpersons of all the SERCs. The FoR's secretariat is provided by CERC, and the Forum meets periodically to consider matters of common regulatory interest submitted by its members or by the Central Government.

The FoR's relationship with APTEL is indirect but significant. Where APTEL's decisions on appeals from Commission orders establish principles of general applicability — for instance, principles governing the methodology for computing open access charges or the norms applicable to multi-year tariff proceedings — the FoR provides a mechanism for the commissions to collectively consider these principles and, where appropriate, adopt common approaches to their application in their respective jurisdictions. The FoR model regulations are typically drafted with reference to APTEL's jurisprudence on the relevant subject, incorporating the legal principles that APTEL has established and translating them into regulatory instruments that the individual commissions can adopt with appropriate state-specific adaptations.

The FoR has issued model regulations and guidance notes covering matters including: multi-year tariff principles for distribution utilities;

standards of performance for distribution licensees; consumer grievance redressal mechanisms including the CGRF and Electricity Ombudsman framework; open access charges and conditions; renewable purchase obligation frameworks and REC mechanisms; and the regulatory treatment of energy storage. These model instruments have been adopted (with varying degrees of fidelity to the model) by many SERCs, contributing to a degree of regulatory convergence across the country that reduces regulatory fragmentation and its adverse consequences for investors who operate across multiple state jurisdictions.

CHAPTER EIGHT (EXTENDED ANALYSIS)

Distribution Franchisee, PPP Models & Input-Based Franchisee Framework

Private Sector Participation in Distribution Without Full Privatisation: The Franchisee Route

8.7 Distribution Franchisee Model: Legal Basis and Commercial Structure

The distribution franchisee model represents an important intermediate option for engaging private sector management expertise and capital in electricity distribution without the full privatisation of the distribution utility's assets and the transfer of its distribution licence to a private entity. Under the franchisee model, the distribution licensee retains its licence, its assets, and its regulatory relationship with the SERC, but delegates the responsibility for distribution operations within a defined sub-franchise area to a private franchisee entity under a commercial franchisee agreement. The franchisee takes responsibility for: collecting electricity bills from consumers; reducing AT&C losses through network improvements and anti-theft enforcement; providing quality of supply to consumers in accordance with the standards specified in the franchisee agreement; and investing in distribution infrastructure improvements within the franchise area up to a specified capital expenditure level.

The legal basis for the franchisee arrangement in the Electricity Act, 2003 is found in Section 13, which provides that any licensee may authorise any person to do any act or thing which the licensee itself is authorised to do under this Act, subject to such conditions and restrictions as may be specified by the Appropriate Commission. Section 13 is the statutory authority for the distribution licensee to enter into a franchisee arrangement with a private entity, delegating to the franchisee the operational aspects of distribution within the franchise area while the licensee retains ultimate regulatory responsibility and accountability for the supply of electricity to consumers in that area.

The Input-Based Franchisee (IBF) model, developed by the Ministry of Power and piloted in several states from around 2007 onwards, is the most widely adopted variation of the franchisee model in India. Under the IBF model, the franchisee's commercial incentive structure is designed around the concept of an "input energy" price at which the distribution licensee transfers electricity to the franchisee at the supply point of the franchise area. The franchisee purchases electricity from the distribution licensee at the agreed input energy price and is responsible for selling that electricity to consumers at the applicable retail tariff. Any reduction in AT&C losses below the baseline level results in additional revenue for the franchisee (since it can sell more electricity from the same input energy), while any increase above the baseline results in financial losses for the franchisee. The IBF model thus directly aligns the franchisee's financial interest with the objective of AT&C loss reduction, creating a strong private sector incentive for the investments and enforcement actions needed to reduce losses.

The experience with the IBF model has been mixed. In areas where private operators have implemented the model successfully — including parts of Bhiwandi in Maharashtra (operated by Torrent Power), Agra in Uttar Pradesh, and certain divisions in Madhya Pradesh — significant reductions in AT&C losses and improvements in billing efficiency and revenue collection have been achieved. In areas where the model has been less successful, the difficulties have typically involved: unrealistic AT&C loss reduction targets that make the franchise area commercially unviable; inadequate support from the distribution licensee in providing reliable electricity supply to the franchise area (since the franchisee cannot reduce distribution losses if the electricity it receives from the distribution licensee is itself inadequate in quantity and quality); disputes over the metering and settlement arrangements at the franchise boundary; and regulatory uncertainty about the relationship between the franchisee's operations and the SERC's jurisdiction over consumer complaints and service quality standards within the franchise area.

The regulatory treatment of franchise arrangements by the SERCs has been an important factor in the success or failure of specific franchisee initiatives. SERCs have addressed questions including: whether consumer complaints in a franchise area should be addressed to the franchisee or to the distribution licensee (and the answer is the latter, since the distribution licensee retains its regulatory obligations to all consumers in its area of supply regardless of the existence of a franchise arrangement); whether the franchisee's capital expenditure in the franchise area should be treated as part of the distribution licensee's regulated asset base for tariff purposes (this depends on the specific terms of the franchise agreement and the Commission's treatment of third-party investments in the distribution network); and whether the franchisee is subject to the SERC's standards of performance for distribution utilities or is governed only by the standards specified in the franchise agreement (the latter approach has generally been adopted by the commissions, recognising that the franchisee is a commercial entity rather than a licensed utility).

8.8 Smart Grid and Advanced Metering Infrastructure: Regulatory Dimensions

The deployment of smart grid technology — encompassing Advanced Metering Infrastructure (AMI), distribution automation, distribution management systems (DMS), and demand response programmes — is creating new regulatory challenges and opportunities for the electricity distribution sector. Smart grid technology enables: two-way communication between the utility and the meter, allowing remote meter reading and remote disconnection/reconnection; real-time monitoring of network conditions including voltage, current, and power quality parameters at multiple points in the distribution network; the implementation of time-of-use (TOU) tariffs that reflect the time-varying cost of electricity supply; and the integration of distributed energy resources (including rooftop solar, battery storage, and electric vehicle charging) into the distribution network management framework.

The regulatory framework for smart metering and smart grid deployment in India is still evolving, with CERC and the SERCs developing their respective approaches to the many regulatory questions that smart grid technology raises. These questions include: the allocation of smart metering costs between the distribution utility (whose operational efficiency benefits from smart metering through reduced meter reading costs and improved tamper detection) and consumers (who benefit from more accurate billing and potentially from time-of-use tariff options); the data governance framework for smart meter data (including questions of consumer privacy, data ownership, and the use of consumption data for billing, demand forecasting, and commercial analytics); the technical standards applicable to smart meters and their communication infrastructure (specified by the CEA under Section 73(b) and elaborated in the CERC and SERC metering regulations); and the regulatory treatment of demand response programmes that use smart metering infrastructure to adjust consumer loads in response to grid conditions or price signals.

The Ministry of Power's Revamped Distribution Sector Scheme (RDSS) has provided significant capital funding for the deployment of smart (prepaid) meters to domestic, industrial, and commercial consumers across the country, with ambitious targets for the number of smart meters to be installed. The prepaid metering model mandated under RDSS — under which consumers pay for electricity in advance and the meter automatically disconnects when the prepaid balance is exhausted — is intended to improve revenue collection efficiency, reduce theft, and eliminate the need for meter readers and bill collection agents. The regulatory implications of prepaid metering for consumer protection — particularly the question of whether a consumer who runs out of prepaid balance has any right to continue supply pending payment — have been addressed by some SERCs in their metering regulations, which typically provide for a minimum emergency credit facility to prevent the immediate disconnection of domestic consumers who exhaust their prepaid balance.

CHAPTER TWO (DEEP ANALYSIS)

Constitutional Law of Electricity: Case Law and Doctrine

Landmark Constitutional Decisions, Fundamental Rights in Electricity Regulation, and Federalism in Practice

2.9 The Constitution Bench Decisions on Electricity Regulation

The constitutional validity of the electricity regulatory framework has been considered in a number of significant decisions by the Supreme Court of India, several involving Constitution Benches of five or more judges. These decisions have settled fundamental questions about the distribution of legislative competence over electricity, the validity of regulatory institutions, and the constitutional limits of regulatory authority in this sector. A survey of the principal constitutional decisions and the principles they establish is essential for practitioners who must advise on the constitutional dimensions of electricity regulatory issues.

The Supreme Court has definitively held that the placement of "Electricity" in Entry 38 of List III enables Parliament to enact comprehensive legislation that occupies the field of electricity regulation, and that the Electricity Act, 2003 constitutes such a comprehensive enactment. Following the Act's commencement, state laws that are inconsistent with the EA 2003 are rendered void to the extent of the inconsistency under Article 254(1). Courts have rejected arguments that the EA 2003 represents an encroachment on state authority simply because it establishes central regulatory standards that constrain state governments' ability to set electricity tariffs or manage their electricity utilities in ways inconsistent with the central framework. The position is that Parliament, in exercise of its concurrent legislative authority under Entry 38, may legitimately legislate in a manner that imposes national standards and constraints on the exercise of state authority over concurrent subjects, provided it does not encroach on subjects that fall exclusively within the State List.

The constitutional challenge to the jurisdiction of APTEL — specifically the argument that the creation of APTEL as the exclusive appellate forum for Commission orders unconstitutionally ousts the jurisdiction of the High Courts under Article 226 — was considered and rejected by the Supreme Court in a series of decisions. The Court held that the creation of APTEL does not oust Article 226 jurisdiction; it merely provides an alternative and specialised forum for the resolution of electricity regulatory disputes. The High Courts retain their constitutional jurisdiction under Article 226 but exercise it with restraint where APTEL provides an efficacious remedy, consistent with the well-established principle that the existence of an alternative remedy is a relevant consideration (though not an absolute bar) in the exercise of High Court writ jurisdiction.

The constitutional question of whether the tariff-setting function of the regulatory commissions involves an unconstitutional delegation of legislative power — on the basis that tariffs are a matter of policy that cannot be delegated to an administrative body — was considered and resolved in favour of the constitutional validity of the delegation. The Court held that the Electricity Act, 2003 provides a comprehensive set of principles and guidelines for tariff determination (in Section 61 and the referenced Tariff Policy) that constitute a sufficient legislative policy framework within which the commissions exercise their delegated tariff-setting authority. The delegation is not naked or unguided; it operates within a detailed statutory and policy framework that ensures consistency with the legislature's objectives and protects the interests of all affected parties. This holding is consistent with the general principles established in the landmark delegation of power cases of the Supreme Court.

2.10 Article 19(1)(g) in the Electricity Sector: Limits of Regulatory Power

The fundamental right to carry on any occupation, trade, or business under Article 19(1)(g), subject to reasonable restrictions under Article 19(6), generates a rich vein of constitutional law in the electricity sector. Generating companies, distribution utilities, trading licensees, and large industrial consumers have all invoked Article 19(1)(g) in challenging specific regulatory actions or requirements that they contend unreasonably restrict their freedom to conduct their electricity sector businesses.

The principal test for the constitutional validity of regulatory restrictions on the right to carry on business in the electricity sector under Article 19(6) is whether the restriction is a reasonable restriction "in the interests of the general public." Courts have consistently held that a wide range of regulatory measures applicable to electricity sector participants satisfy this test, on the grounds that: electricity is an essential service affecting the health, welfare, and economic productivity of the entire population; the electricity sector exhibits natural monopoly characteristics in its network segments that justify regulatory controls to prevent the abuse of monopoly power; and the technical complexity of the electricity system requires mandatory compliance with technical and safety standards that are essential for the protection of public safety. Specific regulatory requirements that have been upheld as reasonable restrictions under Article 19(6) include: the licensing requirement for distribution and trading activities; the non-discriminatory open access obligation imposed on transmission and distribution licensees; the obligation to install and maintain accurate meters; and the mandatory standards of performance and consumer protection requirements imposed on distribution utilities.

However, courts have not upheld all regulatory restrictions under Article 19(6) as automatically reasonable. Regulatory requirements that are disproportionate to the regulatory objective they serve, or that are imposed without adequate procedural safeguards, or that create arbitrary distinctions among similarly situated entities may be challenged successfully under Article 14 read with Article 19(1)(g). The constitutional review of regulatory restrictions thus operates as an important check on the exercise of regulatory power, ensuring that regulatory authorities respect both the substantive rights of regulated entities and the procedural requirements of fair and rational decision-making.

2.11 Environment, Electricity, and the Constitutional Framework

The environmental dimensions of electricity sector governance have increasingly prominent constitutional implications as India's energy transition accelerates. The constitutional right to a clean environment, derived from Article 21's right to life in the landmark Supreme Court decision in Subhash Kumar v. State of Bihar, has been applied in a range of environmental challenges to electricity sector projects, including challenges to thermal power plant emissions, challenges to hydroelectric project construction in ecologically sensitive areas, and challenges to transmission line routing through protected forest areas.

The constitutional framework for environmental protection in the electricity sector operates at multiple levels. At the legislative level, the Environment (Protection) Act, 1986 and the Forest Conservation Act, 1980 impose substantive requirements for environmental clearance, forest diversion permissions, and pollution control compliance that apply to electricity generation and transmission infrastructure. These environmental requirements are enforced by the Central and State Pollution Control Boards, the Ministry of Environment, Forest and Climate Change, and, ultimately, by the National Green Tribunal established under the National Green Tribunal Act, 2010. The National Green Tribunal has jurisdiction over environmental disputes including challenges to the environmental clearances and forest clearances granted for electricity sector infrastructure, and its decisions are subject to appeal to the Supreme Court.

The intersection between the electricity regulatory framework administered by CERC and the SERCs and the environmental regulatory framework administered by the environmental authorities creates complex multi-forum governance dynamics. A major hydroelectric project, for instance, requires: the concurrence of the CEA for its techno-economic viability; the approval of the Central Government for the development of inter-state rivers; environmental clearance from the Ministry of Environment, Forest and Climate Change; forest clearance for the diversion of forest land for the project; wildlife clearance where the project area overlaps with wildlife habitats; CERC or SERC approval for the power purchase agreements from the project; and CERC's adoption of the competitive bidding tariff (or SERC approval of a regulated tariff). The management of these multiple regulatory approvals, each from a different authority and subject to a different legal framework, requires sophisticated project governance and legal management capabilities and is a significant source of regulatory delay and cost in the development of large electricity infrastructure projects.

CHAPTER FIVE (DEEP ANALYSIS)

CERC Tariff Regulation: Detailed Methodology and Recent Developments

Capital Cost Norms, Return on Equity, Renewable Energy Tariffs, and the Transition to Competitive Markets

5.10 The Capital Cost Framework in Cost-Based Tariff Regulation

The determination of the capital cost eligible for tariff recovery under the cost-of-service methodology is one of the most technically complex and commercially contentious aspects of CERC's tariff regulatory function. The capital cost framework determines the asset base on which the regulated utility earns its permitted return, and its determination therefore has a direct and substantial impact on the tariff payable by procurers and ultimately by electricity consumers. The larger the allowed capital cost, the higher the tariff; the lower the allowed capital cost, the lower the tariff and the more efficient the deployment of consumer resources.

CERC's Terms and Conditions of Tariff Regulations specify the approach to capital cost determination. The regulations provide that the tariff determination shall be based on the capital cost of the generating station or transmission system element as determined in accordance with the Regulations, which specify benchmark capital cost norms for new projects (representing the capital cost of efficiently developed projects of the relevant type at current prices) and capital cost scrutiny procedures for existing projects (in which the Commission reviews and approves the capital cost claimed by the regulated entity for the purposes of tariff determination).

The capital cost scrutiny process involves a detailed examination of the project's cost components including civil works, mechanical and electrical equipment, transmission infrastructure, development costs, interest during construction, and pre-operative expenses. CERC disallows costs that are considered excessive or imprudent — for instance, costs arising from unreasonable delays in project construction that could have been avoided by more diligent project management, or costs associated with equipment procurement from related parties at prices above the market rate. The disallowance of imprudent costs is a fundamental principle of cost-of-service regulation: the regulator's function is to allow the recovery of prudently incurred costs, not to underwrite the consequences of management inefficiency or commercial mismanagement at the ratepayers' expense.

For generation projects, the CERC Regulations specify benchmark capital cost parameters for different technologies (coal, gas, nuclear, large hydro, pumped storage) based on the CEA's assessment of achievable project costs for efficiently managed new projects. These benchmark costs are reviewed and updated periodically to reflect changes in equipment costs, construction costs, and financing conditions. Generating companies that develop projects with capital costs below the applicable benchmark benefit from additional return on equity (since their actual return on investment exceeds the permitted return on the benchmark cost), creating an incentive for efficient project development and cost management within the regulated tariff framework.

The debt-equity ratio assumed for the purposes of tariff determination under the CERC Regulations is typically 70:30, reflecting the standard project finance structure for Indian electricity infrastructure. The annual fixed charge computation for each year of the tariff period is based on: depreciation on the debt component of the capital cost (calculated using the Straight Line Method as specified in the Regulations); return on equity on the equity component of the capital cost at the rate specified in the Regulations; interest on the outstanding loan at the applicable rate; and operation and maintenance expenses at the normative level specified in the Regulations. The resulting aggregate revenue requirement is the annual fixed charge payable by procurers regardless of the generating station's actual output, subject to the achievement of the minimum declared availability level specified in the PPA.

5.11 Return on Equity: Regulatory Principles and Current Framework

The rate of return on equity (RoE) permitted to regulated electricity utilities under the CERC's cost-of-service framework is one of the most contentious parameters in electricity tariff regulation. The permitted RoE determines the financial return that investors in regulated electricity infrastructure can earn on their capital, directly affecting the attractiveness of regulated electricity infrastructure as an investment class and the ability of regulated utilities to raise equity capital on reasonable terms. Setting the permitted RoE too low deters investment in regulated infrastructure and contributes to the capacity shortfall; setting it too high results in excessive tariffs and a transfer of wealth from consumers to investors.

CERC's approach to RoE determination has evolved across multiple tariff regulatory periods. The CERC Tariff Regulations specify a post-tax return on equity that is determined as the risk-free rate (typically derived from the yield on long-term Government of India securities) plus a risk premium that reflects the systematic risk of regulated electricity infrastructure investment relative to the risk-free alternative. In recent regulatory periods, CERC has adopted a post-tax RoE of 15.5 per cent per annum on the normative equity component of the capital cost, subject to a "trajectory reduction" approach in subsequent tariff periods that gradually reduces the permitted RoE as the project's financing risk diminishes with the passage of time and the repayment of project debt.

The determination of the risk premium applicable to regulated electricity infrastructure — and the relationship between the permitted RoE and the Weighted Average Cost of Capital (WACC) concept used in economic regulation in other jurisdictions — has been a subject of academic and regulatory debate. Some commentators and utilities have argued that CERC should adopt a WACC-based approach to return determination that explicitly models the risk of debt and equity in the capital structure of regulated utilities, consistent with the approach adopted by economic regulators in the United Kingdom, Australia, and other mature regulatory systems. CERC has engaged with these arguments in successive regulatory consultations but has generally maintained a modified cost-plus approach rather than a pure WACC framework, citing the practical difficulties of implementing a WACC approach in the Indian regulatory context given the absence of liquid long-term capital markets from which to derive market-based risk premium estimates.

5.12 Renewable Energy Tariff Regulation: Special Considerations

The tariff regulation of renewable energy projects under Section 62 of the Electricity Act, 2003 presents special considerations that distinguish it from the tariff regulation of conventional generating stations. The cost structure of renewable energy projects is fundamentally different from that of thermal generating stations: while thermal stations have significant ongoing fuel costs that constitute the variable component of their tariff, renewable energy projects have very low or zero fuel costs and instead have high capital costs that constitute the overwhelming majority of their levelised cost of energy. The predominance of capital costs means that the key parameters for renewable energy tariff determination under Section 62 are the benchmark capital cost, the debt-equity ratio, the cost of debt, the permitted return on equity, and the normative capital expenditure recovery period — rather than the normative heat rates and fuel prices that dominate conventional station tariff determination.

CERC issues separate Terms and Conditions of Tariff Regulations for renewable energy generating stations under Section 62, specifying benchmark capital cost norms, debt-equity ratios, O&M expense norms, and normative generation parameters (including the Capacity Utilisation Factor or CUF for solar projects, and the Plant Load Factor or PLF for wind and biomass projects) for different renewable energy technologies and different geographic resource zones. The CUF/PLF norms specify the minimum utilisation level that the renewable generator is expected to achieve; performance below this norm results in a reduced energy charge payment, while performance above it results in additional payment at the specified rate.

The declining cost of renewable energy — driven by technological innovation, economies of scale in manufacturing, and competitive pressure in procurement — has progressively reduced the relevance of the Section 62 cost-based tariff pathway for new renewable energy projects. The tariffs discovered through competitive bidding under Section 63 have fallen dramatically over the period 2010–2024, from levels of Rs. 10–12 per kWh for solar in the early programmes to below Rs. 2.50 per kWh for large ground-mounted solar in recent auctions. At these competitively discovered price levels, the Section 62 benchmark cost-based approach typically produces higher tariffs than competitive bidding, making Section 63 the natural procurement pathway for new renewable capacity and limiting the practical application of Section 62 renewable energy tariff determination to legacy projects and specific contexts where competitive procurement is not feasible.

5.13 CERC and the Development of Energy Storage Regulation

Energy storage systems, particularly battery-based energy storage systems (BESS), present novel regulatory challenges for CERC given their dual character as both generation resources (when discharging) and load resources (when charging). The regulatory treatment of storage in the existing tariff, market, and grid code frameworks designed for conventional generating stations and for demand-side consumers is not straightforward, and CERC has been progressively developing a comprehensive regulatory framework for the participation of energy storage in the Indian electricity market.

The key regulatory issues that CERC has addressed in relation to energy storage include: the definition of "Energy Storage System" and its classification in the regulatory framework (CERC has defined ESSs as a category distinct from both conventional generating stations and conventional loads, with a specific regulatory treatment); the connectivity requirements for ESSs connecting to the ISTS (addressed in the 2022 Connectivity and GNA Regulations); the tariff framework for stand-alone ESSs procured by distribution utilities or system operators under competitive procurement (CERC has approved tariff determination under Section 63 for storage projects procured under Government tender processes); the ancillary services framework applicable to ESSs given their inherent capability to provide fast frequency response and other ancillary services; and the market participation rules for ESSs in the power exchange markets, including the conditions under which storage operators can arbitrage between the charging and discharging markets.

The development of pumped storage hydroelectric projects as a large-scale storage technology, distinct from lithium-ion battery storage but serving similar grid stabilisation functions, has also required regulatory attention from CERC. Pumped storage projects are hydro generation projects from the perspective of their physical operation (using water stored at different elevations to generate electricity in a conventional hydro turbine-generator), but they operate on a fundamentally different commercial basis from run-of-river or reservoir hydro projects since their energy output is determined by market conditions rather than by water availability. CERC has developed regulatory provisions for the tariff treatment and market participation of pumped storage projects that recognise their storage character while fitting within the existing hydro project tariff framework.

CHAPTER SIX (DEEP ANALYSIS)

SERCs: Retail Tariff Design, Agricultural Electricity, and Distribution Reform

Tariff Structure Principles, Agricultural Supply Governance, Smart Meter Deployment, and Demand-Side Management

6.8 Retail Electricity Tariff Structure: Principles and Design

The design of retail electricity tariff structures by State Electricity Regulatory Commissions involves complex trade-offs among multiple policy objectives including: economic efficiency (ensuring that tariffs reflect the marginal cost of electricity supply so as to encourage efficient use of electricity and discourage wasteful consumption); equity and affordability (ensuring that lower-income consumers can afford a minimum level of electricity supply); financial sustainability (ensuring that the distribution utility's revenues are sufficient to cover its costs and maintain its financial viability); and administrative simplicity (ensuring that tariff structures are understandable to consumers and administratively manageable for the utility).

The typical retail tariff structure adopted by Indian SERCs for domestic consumers involves a lifeline tariff rate for a basic consumption slab (typically the first 50–100 units per month), a standard domestic tariff rate for the next consumption slab, and a higher tariff rate for consumption above a specified level. This multi-slab structure is designed to provide affordable electricity for low-consumption (and by implication lower-income) households while ensuring that higher-consumption households pay progressively higher tariffs that approach or exceed the cost of supply. The implicit assumption of the multi-slab structure — that lower consumption levels are associated with lower income levels — is a rough approximation that does not always hold in practice (wealthy households may have low consumption due to use of energy-efficient appliances or small household size, while lower-income households may have higher consumption due to larger family size) but provides a workable basis for socially progressive tariff design in the absence of consumption-independent income data.

The agricultural tariff structure in most Indian states is either a flat rate per connected horsepower of pump capacity (an unmetered supply arrangement) or a very low per-unit tariff for metered agricultural supply. Flat-rate agricultural tariffs create well-known incentive distortions: they provide no incentive for farmers to use electricity efficiently, since the tariff is independent of consumption; they create an incentive for farmers to install larger pump capacity than necessary (since the flat-rate tariff does not increase with pump size beyond the connected capacity basis); and they make it impossible to measure the actual electricity consumption of agricultural users, obscuring the true AT&C loss levels of distribution utilities serving rural areas with large agricultural loads.

The progressive introduction of agricultural metering, while commercially sensible and technically feasible with the deployment of smart meters under the RDSS scheme, is a politically sensitive matter that state governments have been reluctant to mandate for fear of voter backlash from farming communities. The regulatory commissions have been more willing to specify the principle of agricultural metering and to prescribe timelines for its implementation, but the enforcement of agricultural metering requirements by state governments has been inconsistent. The Tariff Policy's guidance on agricultural metering — requiring SERCs to specify plans for 100 per cent agricultural metering on a time-bound basis — has not consistently been translated into action, reflecting the dominance of political economy considerations over regulatory principles in this domain.

6.9 Time-of-Use Tariffs and Demand Response

Time-of-use (TOU) tariffs — electricity tariff structures in which the per-unit price of electricity varies by time of day or time of year to reflect the time-varying cost of electricity supply — are emerging as an important tool for managing electricity demand and integrating variable renewable generation into the electricity system. At times of the day when renewable generation is abundant (typically midday for solar, evening for wind) and system costs are low, TOU tariffs would incentivise consumers to shift flexible loads to these periods. At times when the system is tight and generation costs are high (early morning and evening peaks), TOU tariffs would incentivise load reduction or shifting.

Several SERCs have introduced TOU tariff provisions for large industrial and commercial consumers as part of their tariff orders, specifying peak-period and off-peak-period rates that provide financial incentives for load shifting. However, the widespread application of TOU tariffs to smaller industrial, commercial, and domestic consumers requires smart metering infrastructure capable of recording and differentiating consumption by time of use, which is only now becoming broadly available with the deployment of smart meters under the RDSS scheme. As smart meter penetration increases, the scope for TOU tariffs to serve as a demand management tool will expand significantly, and SERCs are beginning to develop the regulatory framework for time-differentiated retail tariffs applicable to smart-metered consumers.

Demand response programmes — arrangements under which consumers agree to reduce their electricity consumption when requested by the system operator or the distribution utility, in exchange for financial compensation or tariff benefits — are a form of flexible electricity service that can substitute for generator-based flexible capacity in managing grid balance. CERC and the SERCs are developing regulatory frameworks for demand response, including the definition of eligible demand response resources, the compensation mechanisms, the metering and verification requirements for demand response events, and the accounting treatment of demand response services in the utility's regulated revenue framework. Demand response is expected to become an increasingly important element of the Indian electricity market's flexibility toolkit as variable renewable energy penetration increases and the requirement for system flexibility grows.

6.10 Regulatory Compact and Allowed Revenue Framework

The "regulatory compact" — the implicit understanding between the regulated utility and the regulatory commission that the utility will be allowed to earn a fair return on its investment in regulated assets in exchange for its acceptance of the obligations of serving as a licensed electricity supply entity — is a foundational concept in the jurisprudence of electricity regulation. The regulatory compact forms the constitutional and contractual basis for the private sector's willingness to invest in regulated electricity infrastructure under the risk of regulatory expropriation: private investors will commit capital to regulated electricity infrastructure only if they are confident that the regulatory framework provides a credible and durable commitment to allow the recovery of prudently incurred costs and a reasonable return on investment.

The concept of regulatory compact has been invoked in legal proceedings before APTEL and the Supreme Court in cases where regulated utilities have argued that Commission orders on tariff determination fail to provide them with a sufficient return to support continued investment in regulated infrastructure. APTEL has generally upheld the regulatory compact principle, holding that the Commission's tariff determination must at minimum allow the utility to recover its prudently incurred costs and earn a return sufficient to maintain the utility's financial viability and capacity to continue providing regulated services. Tariff orders that result in systematic under-recovery by distribution utilities — such that the utility's financial position deteriorates to the point where it cannot service its debt, attract equity capital for expansion, or maintain the quality of its distribution network — are vulnerable to challenge on the grounds that they breach the regulatory compact and deprive the utility of the financial conditions necessary for the sustained provision of regulated services.

The practical challenge of implementing the regulatory compact in the context of state distribution utilities — which are government-owned entities with state government guarantees backing their debt — is that the state government's ability to absorb the financial consequences of below-cost tariff setting (through budgetary subsidies and capital injections) can obscure the true financial impact of tariff regulation for extended periods. When the accumulated financial stress eventually reaches a crisis point (as has occurred in several states with very high DISCOM debt), the remediation requires a major restructuring exercise involving state government fiscal resources, central government support schemes, and Commission participation in developing a credible recovery plan. The UDAY scheme and its successors represent the attempts of the Central Government to provide structured support for DISCOM financial recovery while creating incentives for the underlying structural reforms — particularly tariff rationalisation and AT&C loss reduction — that are necessary to prevent the recurrence of the financial crisis.

CHAPTER NINE (DEEP ANALYSIS)

Renewable Energy Procurement: Legal Framework and Market Evolution

Policy Architecture, Bidding Frameworks, Grid Integration, and the 500 GW Target

9.10 Renewable Energy Legal Architecture: An Overview

The legal and regulatory architecture for renewable energy in India is a multi-layered framework that draws on provisions of the Electricity Act, 2003, delegated legislation in the form of rules and regulations, policy documents including the National Electricity Policy and the Tariff Policy, and specific sectoral policies for individual renewable energy technologies. The framework has evolved rapidly over the period since 2010, driven by the dramatically declining costs of solar and wind energy, the Central Government's ambitious renewable energy targets, and the increasing recognition of renewable energy's critical role in India's energy security, economic competitiveness, and climate commitments.

At the legislative level, the primary provisions relevant to renewable energy are: Section 3 (which requires the National Electricity Policy to promote the generation of electricity from renewable sources); Section 86(1)(e) (which requires SERCs to specify Renewable Purchase Obligations and to promote grid connectivity for renewable generators); Section 61(h) (which requires the Appropriate Commission to be guided by the principle of promoting co-generation and generation from renewable sources); Section 63 (which enables competitive procurement of renewable energy on a tariff-adoption basis); and the provisions of Part II relating to the Tariff Policy, which includes detailed guidance on the RPO framework, the REC mechanism, and the competitive bidding framework for renewable energy. These provisions collectively establish the legal basis for the entire renewable energy regulatory framework, while leaving the specifics of implementation to be elaborated through delegated legislation and regulatory instruments.

The Solar Energy Corporation of India (SECI), established in 2011 under the Companies Act as a Government of India enterprise under the Ministry of New and Renewable Energy, has emerged as the principal central agency for large-scale competitive procurement of solar (and now wind, hybrid, and storage) energy in India. SECI conducts competitive tenders under Section 63 for solar and wind capacity to be installed by developers across the country, with the output sold to state distribution utilities or to central government consumers at the competitively discovered tariff. The SECI model has been widely replicated by state governments (through their own renewable energy development corporations) and by distribution utilities directly, and has been the mechanism through which the vast majority of India's renewable capacity additions since 2015 have been procured.

9.11 Hybrid Renewable Energy Projects: Regulatory Treatment

Hybrid renewable energy projects — combining wind and solar generation at the same location, or combining renewable generation with battery energy storage — represent an important evolution in renewable energy project design that is reshaping the regulatory framework. Hybrid projects are motivated by the complementary generation profiles of wind and solar energy (solar generates primarily during daytime hours while wind generation peaks in the evening and night in most Indian resource locations) and by the ability of battery storage to smooth the variable output of renewable generation and provide reliable supply during specific time windows.

The regulatory framework for wind-solar hybrid projects was addressed by CERC through the issuance of specific hybrid project connectivity and tariff regulations. The key regulatory questions for hybrid projects include: the determination of the "installed capacity" of a hybrid project for the purposes of connectivity to the grid (given that the wind and solar components may individually be sized larger than the grid connection capacity, with the battery or the natural complementarity of the two sources ensuring that the actual grid injection does not exceed the connection capacity at any given time); the tariff treatment of hybrid projects under competitive bidding frameworks (with the bidding parameter typically being the per-unit tariff for electricity delivered at the grid connection point, regardless of whether the energy originated from the wind component, the solar component, or the battery); and the appropriate technical requirements for the grid connectivity of hybrid projects given their complex generation profile combining variable and dispatchable components.

The Ministry of New and Renewable Energy's guidelines for the procurement of Round-the-Clock (RTC) renewable energy and Peak Power Supply from renewable energy sources represent the most ambitious evolution of the hybrid project concept. The RTC framework requires the developer to commit to supply a contracted quantum of renewable energy on a round-the-clock basis throughout the year, with penalties for shortfall below the committed level. Meeting the RTC obligation requires the developer to design a portfolio of wind, solar, and storage resources that collectively can provide near-continuous supply regardless of the individual intermittency of each component. CERC's adoption of RTC competitive bidding tariffs under Section 63 has established the regulatory precedent for this category of renewable energy procurement, and several large RTC projects have been procured and are under development.

9.12 Green Energy Open Access: Policy and Legal Dimensions

The Electricity (Promoting Renewable Energy Through Green Energy Open Access) Rules, 2022, notified by the Central Government under Section 176 of the Electricity Act, 2003, introduced a significantly reformed framework for open access to transmission and distribution networks for the procurement of renewable energy by consumers. The 2022 Green Energy Open Access Rules represent a major policy intervention intended to accelerate the adoption of renewable energy by large industrial and commercial consumers through the open access route, addressing structural barriers that had previously limited the uptake of open access renewable energy procurement.

The key features of the 2022 Green Energy Open Access Rules include: reduction of the minimum load threshold for open access eligibility from 1 MW (as specified in many SERCs' open access regulations) to 100 kW, dramatically expanding the universe of consumers who can access electricity from renewable sources through the open access framework; a mandate for processing of green energy open access applications within 15 days (a significant reduction from the typical processing timelines under existing state open access frameworks, which often extended to several months); a limitation on the cross-subsidy surcharge payable on green energy open access transactions (with specific provisions intended to prevent the surcharge from being set at a level that eliminates the cost advantage of green open access over conventional captive supply); and provisions for banking of surplus renewable energy in the network (allowing renewable generators to store surplus energy in the grid during periods of excess generation and recover it during periods of low generation).

The implementation of the 2022 Green Energy Open Access Rules by SERCs and state governments has been uneven. Several states with large industrial consumers and high-cost distribution utility tariffs have implemented the Rules and seen significant uptake of green open access by industrial and commercial consumers. Other states, concerned about the revenue implications of large consumers departing from the regulated supply of the distribution utility, have been slower to implement the Rules or have imposed conditions and charges that limit their practical utility. The tension between the Central Government's green open access policy objectives and the states' interest in protecting the financial position of their distribution utilities is a recurring theme in the implementation of open access reforms and reflects the fundamental political economy challenge of electricity sector liberalisation in a federal polity.

9.13 Energy Conservation and Efficiency Regulation

The Energy Conservation Act, 2001 (amended comprehensively in 2022) establishes the legal framework for energy efficiency regulation in India, operating alongside but distinct from the Electricity Act, 2003 framework. The Bureau of Energy Efficiency (BEE), established under the Energy Conservation Act, administers the Standards and Labelling programme for electrical appliances and equipment (which specifies minimum energy performance standards and energy efficiency labels for a wide range of electrical products, from air conditioners and refrigerators to LED lights and electric motors); the Energy Conservation Building Code (which specifies design and construction standards for commercial buildings to minimise their energy consumption); the Perform, Achieve and Trade (PAT) scheme for large energy-intensive industries (which sets energy consumption targets for individual industrial plants and allows plants that exceed their targets to earn Energy Saving Certificates that can be sold to plants that fall short of their targets, creating a market-based incentive for industrial energy efficiency); and, from 2022, the Carbon Credit Trading Scheme (CCTS) which extends the market-based incentive model to greenhouse gas emission reduction across a broader range of sectors.

The intersection of energy efficiency regulation with electricity tariff regulation creates potential synergies and tensions. From a synergy perspective, energy efficiency improvements that reduce electricity consumption by large industrial consumers can reduce their exposure to high electricity tariffs and improve their competitive position, creating a commercial incentive that complements the regulatory obligation of the PAT scheme. From a tension perspective, the reduction in electricity consumption by energy-efficient industrial consumers reduces the revenue of distribution utilities and may worsen their cost recovery position if the tariff structure does not adequately account for declining volumetric consumption. SERCs must therefore factor the expected impact of energy efficiency programmes into their demand forecasts and tariff determinations, ensuring that the distribution utility's allowed revenues are calibrated to the actual electricity demand it is expected to serve rather than to a higher demand level that energy efficiency improvements will prevent from materialising.

Future Architecture: Grid Management, Market Design, and Regulatory Reform

From Bilateral Markets to Competitive Exchanges, from Regional Grids to a Smart National Network

10.9 Market Design for the Indian Electricity System: Current Architecture and Future Direction

The architecture of the Indian electricity market has evolved significantly since the passage of the Electricity Act, 2003, driven by technological change, regulatory innovation, and the growing participation of private sector participants across all segments of the supply chain. Understanding the current market architecture and its likely future evolution is essential for legal practitioners who advise on electricity sector transactions, regulatory proceedings, and dispute resolution.

The current Indian electricity market is best characterised as a hybrid of bilateral contract markets and organised exchange-based markets. The bilateral contract market — in which generators and distribution utilities enter into direct power purchase agreements for defined quantities of electricity at specified tariffs over defined periods — remains the dominant modality for electricity procurement in terms of the volume of electricity contracted and the value of transactions. The vast majority of the electricity consumed by distribution utilities in India is procured under long-term bilateral PPAs of 20–25 years, whether under the cost-based tariff framework of Section 62 or the competitive bidding framework of Section 63. The bilateral PPA market provides long-term revenue certainty to generators and long-term supply security to procurers, supporting the debt financing of capital-intensive infrastructure investments.

The organised exchange-based market — operating through the Indian Energy Exchange and the Power Exchange India Limited under CERC's Power Market Regulations — provides an important complement to the bilateral contract market. The exchange markets serve three principal functions: they provide a price discovery mechanism that reveals the market price of electricity at different times and in different regions, informing the bilateral contract negotiations; they provide liquidity for short-term and balancing transactions, allowing utilities and generators to adjust their supply and demand positions in response to forecast errors and operational requirements; and they facilitate the efficient allocation of electricity across the country by enabling low-cost power to flow from areas of surplus to areas of deficit through the price arbitrage mechanism.

The development of the electricity market towards a more liquid and integrated structure — with greater reliance on market mechanisms and less reliance on bilateral contractual arrangements — is a long-term direction of travel envisioned by the Electricity Act, 2003 and the National Electricity Policy. The evolution towards a capacity market — in which generation capacity is explicitly procured and compensated separately from energy, providing a clear investment signal for the development of new generating capacity — is a potential future direction that has been discussed in regulatory and policy circles but not yet implemented in India. The design of a capacity market for the Indian system, which has very different characteristics from the UK and Australian systems where capacity markets have been implemented, would require careful tailoring to Indian conditions including the highly heterogeneous demand profiles of different states, the large proportion of government-owned generating capacity, and the continuing importance of regulated tariffs for a significant portion of the existing generation fleet.

10.10 Regional Electricity Cooperation and India's Energy Diplomacy

India's electricity sector governance framework extends beyond its national borders through the developing architecture of regional electricity cooperation in South Asia. The South Asian Association for Regional Cooperation (SAARC) Framework Agreement for Energy Cooperation (Electricity), signed by India, Pakistan, Nepal, Bhutan, Bangladesh, Sri Lanka, Afghanistan, and the Maldives, establishes the political framework for regional electricity cooperation, including cross-border electricity trade, joint investment in generation and transmission infrastructure, and harmonisation of technical standards. The legal and regulatory implementation of this framework involves the bilateral and multilateral electricity trade agreements and CERC's cross-border electricity trade guidelines.

India's bilateral electricity relationships with its neighbours are at different stages of development. The relationship with Bhutan is the most mature: India and Bhutan have a long-standing arrangement under which large hydroelectric projects are developed in Bhutan with Indian financial and technical support, and a specified proportion of the electricity generated is exported to India at concessional tariffs in partial repayment for the development financing. This arrangement has made Bhutan one of the highest per-capita electricity exporters in the world and has provided India with a significant source of firm, low-cost renewable energy from Bhutan's large hydroelectric potential. New hydroelectric projects under development in Bhutan under this framework will add significant quantities of renewable energy to India's supply in the coming years.

The electricity trade relationship with Nepal is growing rapidly, with Nepal exporting surplus hydroelectric power to India during the monsoon season when its run-of-river hydro projects generate more electricity than the domestic market can absorb, and India exporting electricity to Nepal during the dry season when Nepali hydro output falls and domestic demand exceeds local supply. The cross-border power transmission links between India and Nepal have been expanded significantly in recent years, and the bilateral electricity trade framework under the India-Nepal Power Trade Agreement provides the regulatory basis for commercial transactions between Indian and Nepali utilities. Bangladesh has emerged as a significant electricity importer from India, with dedicated transmission links connecting the Indian grid to the Bangladeshi grid and long-term supply agreements for hundreds of megawatts of capacity from Indian generating stations.

10.11 Cybersecurity and the Electricity Sector

The increasing digitalisation of electricity sector infrastructure — through the deployment of smart meters, distribution automation systems, supervisory control and data acquisition (SCADA) systems for transmission and generation management, and digital communication networks for grid management — has introduced cybersecurity as a significant regulatory concern for electricity sector governance. A successful cyber attack on the control systems of a large generating station, a regional transmission network, or a grid management control centre could potentially cause widespread electricity outages with severe economic and social consequences.

The regulatory framework for electricity sector cybersecurity in India is evolving rapidly in response to the growing threat landscape. CERC has issued cybersecurity guidelines for the electricity sector, specifying the minimum cybersecurity requirements for connected infrastructure including generating stations, transmission systems, and distribution utilities. The guidelines require covered entities to: maintain an inventory of all connected digital assets; implement technical controls for network segmentation, access management, and intrusion detection; establish incident response procedures for responding to cybersecurity events; conduct regular cybersecurity audits and vulnerability assessments; and report significant cybersecurity incidents to CERC and the relevant national cyber security agencies. The National Power Portal and the POSOCO data management systems, which collect and process large volumes of operational data from electricity utilities across the country, are subject to heightened cybersecurity requirements given the sensitivity of the data they contain and the potential for their compromise to disrupt the management of the national electricity grid.

The legal framework for electricity sector cybersecurity draws on multiple regulatory instruments: the Information Technology Act, 2000 and its associated rules provide the general legal framework for cyber crime and data protection; the National Critical Information Infrastructure Protection Centre (NCIIPC) designation of electricity sector infrastructure as critical information infrastructure imposes additional security requirements; and sector-specific CERC and SERC regulations address the operational aspects of cybersecurity in electricity infrastructure. The coordination between the electricity sector regulators and the national cybersecurity authorities — including NCIIPC, the Computer Emergency Response Team of India (CERT-In), and the National Cyber Security Coordinator — is essential for the effective management of cybersecurity risks in a sector as nationally critical as electricity.

10.12 The Way Forward: A Comprehensive Reform Agenda

The Indian electricity sector faces a confluence of challenges and opportunities that will shape the evolution of its legal and regulatory framework over the coming decade. The successful management of this transition will require coordinated action by the Central Government, state governments, regulatory commissions, the judiciary, electricity utilities, private investors, and civil society, guided by a clear understanding of the legal framework within which these actors operate and the regulatory instruments available to support the desired outcomes.

The principal elements of the comprehensive reform agenda that the electricity sector's stakeholders and regulators are developing include: the financial rehabilitation of state distribution utilities through a combination of tariff rationalisation, AT&C loss reduction, improved revenue collection, and governance improvement; the accelerated expansion of renewable energy capacity to meet India's 500 GW non-fossil fuel target by 2030 and the net zero commitment by 2070; the development of the transmission infrastructure necessary to connect renewable generation in resource-rich areas to load centres, including the Green Energy Corridors and the inter-regional transmission capacity expansions planned in the National Electricity Plan; the integration of large-scale energy storage — including pumped hydro storage and battery energy storage — to provide the flexibility services necessary for a high-renewable electricity system; the development of a competitive market architecture including potential capacity market mechanisms and enhanced market coupling across regions; the deployment of smart grid infrastructure including smart meters, distribution automation, and advanced metering infrastructure at scale; and the development of a robust regulatory framework for new technologies including green hydrogen, electric vehicles, and distributed energy resources.

The legal and regulatory framework established by the Electricity Act, 2003 provides the institutional architecture within which this comprehensive reform agenda must be pursued. The Act's framework of independent regulatory commissions, competitive market principles, and statutory consumer protection obligations has proved sufficiently flexible and durable to accommodate two decades of rapid change in the electricity sector. Its continued evolution through legislative amendment, regulatory reform, and judicial interpretation will determine the pace and effectiveness of India's electricity sector transition in the critical decade ahead.

SUPPLEMENTARY ANALYSIS

Deviation Settlement, Project Finance, and Dispute Resolution

Operational Market Mechanisms, Sector Finance Architecture, Force Majeure, Tax, and Arbitration

S.1 Deviation Settlement Mechanism: Technical and Legal Framework

The Deviation Settlement Mechanism (DSM) is the regulatory instrument through which deviations between the scheduled generation or consumption of a grid-connected entity and its actual metered generation or consumption are valued, settled, and charged. The DSM replaced the earlier Unscheduled Interchange (UI) mechanism, which had operated as India's primary balancing mechanism since 2002, following CERC's issuance of new DSM regulations in 2016. The transition from UI to DSM represented a significant evolution in the regulatory design of the balancing mechanism, moving from a simpler frequency-indexed pricing mechanism to a more sophisticated framework that separates the balancing charge from the frequency signal and provides clearer incentives for grid discipline while accommodating the operational characteristics of variable renewable generation.

Under the DSM framework, each grid-connected entity — generator, distribution utility, open access consumer, or bulk consumer — has a scheduled generation or consumption position for each 15-minute time block of the day, established through the day-ahead scheduling process administered by the Regional Load Despatch Centres. The deviation of the entity's actual metered position from its scheduled position in each 15-minute block is its "deviation" for that block, which is either a positive deviation (more generation than scheduled, or less consumption than scheduled) or a negative deviation (less generation than scheduled, or more consumption than scheduled).

Positive deviations (excess generation or reduced consumption) are valued at the DSM charge applicable to the relevant grid frequency band in the relevant time block: when the grid frequency is high (indicating excess supply), positive deviations are paid at a low DSM charge or may even attract a zero payment, discouraging further over-injection; when the grid frequency is low (indicating deficit supply), positive deviations are paid at a high DSM charge, incentivising entities to inject more energy than scheduled to support grid stabilisation. Negative deviations (shortfall generation or excess consumption) are charged at the corresponding DSM rate: high charges for negative deviations at times of low frequency (when deviation is aggravating the supply deficit) and low charges at times of high frequency (when the deviation is actually corrective).

The DSM mechanism has several important legal and commercial implications for electricity sector participants. For thermal generators, the DSM framework creates financial incentives to follow their despatch schedules closely, since significant positive deviations at times of high grid frequency (which occur when renewable generation is excessive) attract low or zero payment, while significant negative deviations at times of low frequency attract high charges. For renewable generators, the DSM framework is less stringent given the inherent unpredictability of variable renewable output: CERC has provided special provisions for renewable generators under the DSM framework, recognising that they cannot control their output with the same precision as thermal generators and should not be penalised as severely for deviations arising from inherent resource variability rather than operator decisions.

The accounting and settlement of DSM charges involves a complex system of entity-level metering, deviation computation, and financial settlement administered by the Regional Load Despatch Centres. POSOCO (which manages the NLDC and the RLDCs) operates the central DSM settlement system, which produces daily settlement statements showing each entity's deviation by time block and the corresponding financial settlement amount. These settlement amounts are netted against the entity's scheduled energy charges and the resulting net position is settled through the Regional Energy Accounting process. The legal enforceability of DSM settlement claims — including the right of POSOCO to recover unpaid DSM charges from defaulting entities — is established by CERC's DSM Regulations and backed by the grid code compliance framework under the Electricity Act, 2003.

The interface between the DSM mechanism and the ancillary services market is an important and evolving dimension of the balancing framework. As CERC develops a more comprehensive ancillary services market that compensates generators for providing frequency support and reserve services, the role of the DSM mechanism as the primary instrument for balancing incentives will change: the DSM will continue to provide price signals for large and unexpected deviations, while the ancillary services market will provide the commercial framework for the procurement and compensation of voluntary flexibility services. The design of the interaction between these two mechanisms — ensuring that they provide consistent and non-conflicting incentives for grid-connected entities — is a key challenge for CERC's market design programme.

S.2 Electricity Sector Project Finance: Legal Architecture

The financing of electricity infrastructure projects in India — particularly large capital-intensive projects such as thermal power plants, hydroelectric projects, and high-voltage transmission lines — typically involves complex project finance structures in which the project debt is secured primarily on the project's assets and cash flows rather than on the balance sheet of the project developer. The legal architecture of project finance in the electricity sector is a specialised area of practice that requires expertise in electricity regulation, commercial law, banking law, and the specific documentation structures used in Indian infrastructure project finance.

The typical project finance structure for a large electricity project involves: a Special Purpose Vehicle (SPV) company incorporated to own and operate the project; equity contributed by the project developer and, in some cases, co-investors including private equity funds, international development finance institutions, and strategic investors; project debt from a consortium of commercial banks and/or non-banking finance companies, secured by a charge on the SPV's assets and revenues; and a Power Purchase Agreement between the SPV and one or more distribution utilities (or other procurers) that provides the long-term revenue certainty necessary to support the debt financing. The PPA is the cornerstone of the project finance structure: its term, tariff structure, credit quality of the procurer, and legal certainty of enforcement determine the debt serviceability of the project and therefore the terms on which project debt is available.

The credit quality of electricity sector PPAs in India has historically been impaired by the financial weakness of the state distribution utilities that are the primary off-takers under long-term power purchase agreements. Lenders to electricity projects are acutely aware of the risk that a distribution utility off-taker may be unable or unwilling to make timely PPA payments, either because of genuine financial distress or because of disputes about the interpretation of PPA provisions. The payment security mechanisms embedded in electricity sector PPAs — including irrevocable payment letters of credit, escrow accounts funded with electricity tariff revenues, state government guarantees, and the tripartite agreements under which the Reserve Bank of India can direct the state government's bank account to pay the generator in the event of DISCOM default — are designed to mitigate this credit risk and maintain the bankability of electricity infrastructure projects even in the face of weak DISCOM credit.

The legal documentation framework for electricity project finance includes: the Shareholders' Agreement governing the rights and obligations of equity investors in the SPV; the Common Loan Agreement governing the terms of the project debt; the Security Trust Deed establishing the security interest of the lenders in the SPV's assets; the Security Package documentation (including charges on assets, assignment of project documents, pledge of shares, and mortgage of project land); the Escrow Agreement governing the application of project revenues; the Lenders' Step-In Agreement giving the lenders the right to step in and take control of the SPV in the event of a borrower default; and the Direct Agreement between the lenders and the relevant procurer and/or the state government, which typically includes the payment security arrangements and the conditions for lenders' step-in. Each of these documents must be carefully coordinated with the regulatory framework applicable to the relevant type of electricity project, including the Commission's approval requirements for PPA terms and any conditions attached to the project's grid connectivity or transmission access rights.

S.3 Power Finance Corporation and REC Limited: Development Finance Institutions

Power Finance Corporation Limited (PFC) and REC Limited (formerly Rural Electrification Corporation) are the two primary development finance institutions for the Indian electricity sector, providing long-term debt financing to state electricity utilities, central public sector electricity enterprises, and private sector electricity infrastructure developers. Both PFC and REC were established as government-owned financial institutions with a specific mandate to finance electricity sector infrastructure, and both have grown into major non-banking finance companies with loan books of several lakh crore rupees.

PFC was established in 1986 as a public financial institution under the Companies Act, with the mandate of financing the long-term capital requirements of the power sector. PFC's loan portfolio covers the entire electricity supply chain from generation and transmission to distribution and renewable energy. PFC offers project finance for both government-owned and private sector electricity projects, provides refinancing facilities to banks and other financial institutions for electricity sector lending, and administers several Central Government scheme funds including the RDSS scheme. PFC's acquisition of the Government of India's majority stake in REC Limited in 2019 made PFC the parent company of REC, creating an integrated electricity sector development finance group with a combined loan book exceeding Rs. 10 lakh crore.

The legal and regulatory framework applicable to PFC and REC is a complex overlay of the Companies Act (governing their corporate governance), the Reserve Bank of India's regulations for non-banking finance companies (governing their financial operations), the Electricity Act, 2003 framework (governing the regulatory treatment of the electricity utilities to which they lend), and specific government guidelines governing the terms on which they provide financing to different categories of borrowers. PFC and REC have been integral to the financing of several major government electricity sector programmes including the Rajiv Gandhi Grameen Vidyutikaran Yojana (RGGVY) for rural electrification, the R-APDRP and IPDS schemes for distribution sector strengthening, the Ultra Mega Power Project programme, and the RDSS scheme. Their role as development finance institutions — providing long-term financing for infrastructure projects that commercial banks may be reluctant to support given their tenor and risk profile — has been essential for the maintenance of investment flows into the electricity sector even during periods of banking system stress and private investor caution.

S.4 Force Majeure in Electricity Power Purchase Agreements

Force majeure clauses in electricity power purchase agreements define the events beyond the control of either party that excuse non-performance of contractual obligations and govern the commercial consequences of prolonged force majeure events for the PPA relationship. The interpretation and application of force majeure clauses has been a significant source of regulatory and judicial dispute in the Indian electricity sector, particularly in the context of: fuel supply disruptions affecting thermal power generators (including coal shortages arising from Coal India Limited allocation issues, and gas supply curtailments from the KG-D6 basin); natural disasters affecting generation availability (including droughts reducing hydroelectric generation, cyclones damaging generation and transmission infrastructure, and floods affecting coal mine operations); regulatory changes affecting project economics (which are sometimes characterised as force majeure events by the affected party); and global events including the COVID-19 pandemic (which triggered force majeure claims by generators for construction delays, fuel supply disruptions, and demand reductions).

The standard force majeure clause in an Indian electricity PPA typically defines force majeure as any event or circumstance or a combination of events and circumstances that is beyond the reasonable control of the party claiming force majeure; that the party claiming force majeure could not have prevented through the exercise of reasonable diligence; and that has caused or is likely to cause the material failure of the claiming party to perform its obligations under the PPA. The clause typically enumerates specific categories of events that qualify as force majeure (including acts of God such as natural disasters; war, invasion, terrorism, and civil unrest; government actions; epidemics and pandemics; strikes and labour disputes; and in some PPAs, extreme commodity price changes) and excludes from force majeure events that were reasonably foreseeable or preventable, events arising from the claiming party's own negligence or wilful default, and events that merely increase the cost of performance without rendering performance impossible.

CERC and APTEL have developed a body of regulatory and adjudicatory precedent on force majeure in electricity PPAs, addressing questions including: whether a coal supply shortage resulting from a shortfall in Coal India Limited's production constitutes force majeure for a coal-based generator (the answer has generally been that it does not, since the generator had an obligation to arrange alternative coal supplies in the event of a shortfall in its primary supply); whether the regulatory renegotiation of PPA terms by a Commission order constitutes force majeure or change-in-law for the purposes of the affected party's claim for relief; and whether the COVID-19 pandemic and the associated lockdowns and supply chain disruptions qualify as force majeure events under typical electricity PPA force majeure clauses (the answer has generally been yes for construction delays arising directly from lockdown restrictions, but not for broader commercial impacts on project economics that do not directly prevent performance of the specific PPA obligations).

S.5 Goods and Services Tax and the Electricity Sector

The Goods and Services Tax (GST), introduced in India from 1 July 2017 under the Constitution (One Hundred and First Amendment) Act, 2016 and the Central Goods and Services Tax Act, 2017, has significant implications for the electricity sector, even though electricity supply itself is currently exempted from GST. The exemption of electricity from GST means that the supply of electricity to consumers does not attract GST, but this exemption creates a significant "inverted duty structure" problem for the electricity sector: electricity utilities pay GST on their inputs (including generation equipment, transmission hardware, distribution infrastructure, and services) but cannot claim input tax credit on these GST payments because the output (electricity supply) is exempt from GST, resulting in a stranded input tax cost that forms part of the utility's cost base and is ultimately recovered from consumers through the regulated tariff.

The GST treatment of electricity sector inputs has been a significant concern for the sector since the introduction of GST. Equipment and services used in electricity generation, transmission, and distribution attract GST at various rates (including 5 per cent for certain renewable energy equipment and 18 per cent for many other inputs), and the inability of electricity utilities to claim input tax credit on these payments means that the GST cost becomes an embedded cost element in the tariff. The Central Government's decision to maintain the electricity exemption from GST — while transitioning virtually all other goods and services to the GST framework — was driven by concerns about the impact of a sudden GST imposition on electricity tariffs and the political sensitivity of electricity pricing. However, the long-term maintenance of the electricity exemption is seen as an anomaly in the GST framework that distorts the cost structure of the electricity sector and prevents the efficiency gains that would arise from a proper input tax credit chain extending from equipment manufacturers to final electricity consumers.

The regulatory commissions have had to address the GST implications of electricity sector costs in their tariff determination proceedings. CERC and the SERCs have generally recognised the stranded GST cost as a legitimate element of the regulated utility's cost base, eligible for recovery through the regulated tariff. The treatment of GST costs in multi-year tariff proceedings raises questions of cost allocation between regulatory periods: GST paid on capital expenditure in one regulatory period becomes part of the utility's capitalized cost and is recovered through depreciation and return on equity over the asset's useful life, while GST paid on operating expenditure in each year is treated as a current year operating cost. The transition from the pre-GST tax environment to the GST framework required CERC and the SERCs to address the treatment of legacy commitments, the renegotiation of PPAs to reflect GST changes, and the computation of regulatory true-up adjustments arising from the tax change.

S.6 Electricity Disputes and Arbitration: Legal Framework

The resolution of disputes in the electricity sector operates through a hierarchy of forums and mechanisms that reflects both the regulatory character of the sector and the commercial nature of the transactions within it. The principal dispute resolution mechanisms available to electricity sector participants include: regulatory proceedings before CERC or the SERCs; appellate proceedings before APTEL; writ proceedings before High Courts and the Supreme Court; contractual arbitration under the terms of PPAs and other bilateral agreements; and civil litigation before appropriate civil courts. The choice among these mechanisms depends on the nature of the dispute, the parties involved, and the legal framework applicable to the matter in question.

Disputes between parties arising from the interpretation or application of regulated contracts — including power purchase agreements whose tariffs have been adopted under Section 62 or 63, transmission service agreements, and open access agreements — typically fall within the jurisdiction of the Appropriate Commission under Section 86(1)(f) or Section 79(1)(f) of the Electricity Act, 2003, which vest the commissions with the function of adjudicating disputes between licensees and generating companies or between licensees themselves. Commission jurisdiction over PPA disputes has been a significant area of jurisdictional controversy, with generators and procurers sometimes disputing whether a particular PPA dispute falls within the Commission's regulatory jurisdiction (in which case it must be pursued before the Commission) or constitutes a commercial contractual dispute subject to the arbitration clause of the PPA (in which case it must be referred to arbitration under the Arbitration and Conciliation Act, 1996).

The Supreme Court has addressed the jurisdictional boundary between Commission adjudication and contractual arbitration in a number of important decisions. The general principles that have emerged from this jurisprudence are: disputes about the terms of regulated contracts (including the tariff, the payment obligations, and the performance obligations under PPAs adopted by the Commission) fall within the exclusive regulatory jurisdiction of the Commission and cannot be referred to arbitration; disputes of a purely commercial nature arising from bilateral contracts that are not subject to Commission regulatory oversight may be referred to arbitration in accordance with the arbitration clause of the contract; and the existence of a regulatory jurisdiction does not automatically preclude arbitration for all disputes — the specific nature of the dispute must be considered to determine whether it is regulatory or commercial in character.

International arbitration under institutional rules such as those of the International Chamber of Commerce (ICC) or the London Court of International Arbitration (LCIA) is available for electricity sector disputes with an international element, including disputes between Indian electricity utilities and foreign equipment suppliers, disputes arising from international project finance documentation, and disputes between Indian entities and foreign investors in electricity sector projects. The enforceability of international arbitration awards in India under the New York Convention (to which India is a party) and the relevant provisions of the Arbitration and Conciliation Act, 1996 is well-established in general principles, though specific awards have been the subject of enforcement proceedings that have raised questions about the intersection between international arbitration enforcement and the regulatory jurisdiction of the electricity commissions.

S.7 The Electricity Act 2003: An Assessment after Two Decades

The Electricity Act, 2003 has now been in force for over two decades, a period sufficiently long to permit an assessment of its performance against the objectives set out in its Statement of Objects and Reasons. The Act aimed to consolidate existing electricity laws, promote competition, protect consumer interests, supply electricity to all areas, rationalise tariffs, ensure transparent subsidy policies, and promote efficient and environmentally benign policies. How has the Act performed against each of these objectives?

On consolidation of existing laws, the Act has unambiguously succeeded: it replaced three predecessor statutes and created a comprehensive, coherent legislative framework that provides the legal basis for all aspects of electricity sector governance. The clarity and comprehensiveness of the legislative framework under the 2003 Act is a significant improvement over the fragmented legal landscape of the pre-reform period. On the promotion of competition, the Act's achievements are partial but significant: the de-licensing of generation has enabled massive private sector entry into electricity generation, particularly in renewable energy; the mandatory open access framework has created the legal conditions for competitive electricity supply to large consumers; and the Section 63 competitive bidding framework has driven dramatic reductions in electricity generation costs through competitive procurement. However, competition in electricity distribution remains limited, and the retail electricity market for most consumers is still served by regulated monopoly distribution utilities.

On consumer protection, the Act has created a substantially improved institutional framework compared to the predecessor legislation: independent regulatory commissions with tariff-setting authority and consumer protection mandates; the CGRF and Electricity Ombudsman mechanisms for grievance redressal; and the mandatory standards of performance that create regulatory accountability for service quality. However, the practical realisation of these consumer protection provisions has been uneven across states, with wide variation in the quality of regulatory oversight and the responsiveness of distribution utilities to consumer complaints. On the supply of electricity to all areas, India has made extraordinary progress in the post-2003 period, with the Saubhagya scheme achieving near-universal household electrification by 2019 — though the reliability and quality of supply to newly electrified rural areas remains a challenge in many states. On tariff rationalisation and cross-subsidy reduction, progress has been slow, with the political pressures that motivated below-cost agricultural tariffs and extensive cross-subsidisation in the pre-reform period persisting in the post-reform regulatory environment.

The overall assessment is that the Electricity Act, 2003 has been a significantly successful legislative reform, achieving its primary structural objectives of creating a comprehensive legal framework, enabling private sector participation, and establishing independent regulatory institutions, while facing continuing challenges in the distribution segment and in the political economy of tariff rationalisation. The Act's durability and adaptability over two decades of rapid change in the electricity sector — including the renewable energy revolution, the digital transformation, and the growing challenge of climate change — is testament to the quality of its legislative design and to the institutional capacity of the regulatory commissions it established. Its continued evolution through legislative amendment, regulatory innovation, and judicial interpretation will determine whether it remains adequate for the demands of India's electricity sector in the decades ahead.

SUPPLEMENTARY ANALYSIS II

Emerging Legal Issues in the Indian Electricity Sector

Electric Vehicles, Green Hydrogen, Climate Commitments, Insolvency Law, and Consumer Rights in the Digital Era

S.8 Electric Vehicles and the Electricity Legal Framework

The electrification of the transportation sector through the mass deployment of electric vehicles (EVs) is one of the most significant developments reshaping the interface between the electricity regulatory framework and other domains of law and policy. India's National Electric Mobility Mission Plan (NEMMP) and the FAME (Faster Adoption and Manufacturing of Electric Vehicles) scheme launched in 2015 and upgraded in 2019 have provided the policy framework and financial incentives for EV adoption. As the EV fleet grows rapidly, the electricity sector must accommodate the substantial new demands that EV charging places on the distribution network while also capturing the opportunity that EV batteries represent as a new form of distributed flexible resource that can support grid stability.

The legal framework for EV charging in India is still evolving. The Ministry of Power issued guidelines for EV charging infrastructure in 2018 and has updated them subsequently, addressing matters including: the categories of entities that may install and operate EV charging stations (which now include distribution licensees, energy service companies, third-party operators, and the EV owners themselves for their own captive charging needs); the applicable tariff for electricity supplied for EV charging (which is typically a commercial rate specified by the SERC, though some states have introduced specific EV charging tariffs that are lower than the general commercial rate to incentivise EV adoption); the technical requirements for charging equipment including safety standards and metering requirements; and the public access obligations for charging station operators who hold licences to provide public charging services.

A key regulatory question is whether the operator of a public EV charging station is a licensee for the purposes of the Electricity Act, 2003. The Ministry of Power's guidelines clarify that EV charging station operators who supply electricity to third parties (EV users who park at the station) should be treated as licensees and should obtain the applicable licence from the SERC. However, the Ministry has also provided a simplified licensing regime for EV charging stations to encourage rapid deployment, recognising that the imposition of full distribution licensing requirements on small EV charging operators would be disproportionate and would discourage investment in the essential charging infrastructure. The SERC in each state must therefore balance the regulatory objective of ensuring the competence and compliance of EV charging operators with the policy objective of maximising the availability of EV charging infrastructure.

The vehicle-to-grid (V2G) concept — under which EV batteries can discharge energy back into the electricity grid, providing flexibility services to the system operator — has profound implications for the electricity regulatory framework. If a large fleet of EVs can be aggregated to provide demand response and frequency support services, the V2G fleet becomes a significant source of flexible capacity that can partially substitute for battery storage systems and peaking generation. The regulatory framework for V2G services needs to address: the treatment of V2G discharge for metering and billing purposes; the eligibility of EV batteries to participate in ancillary services markets; the technical requirements for V2G-capable charging equipment; and the commercial arrangements between EV owners, aggregators, and the system operator that compensate EV owners for making their battery capacity available for grid services. CERC has issued consultative papers on V2G regulatory design and is expected to develop a comprehensive regulatory framework as V2G technology matures and commercial deployment begins in India.

The impact of widespread EV adoption on the distribution network is a major planning and regulatory concern for SERCs and distribution utilities. EV charging loads, particularly fast charging and high-power charging at commercial locations, can create significant peaks in demand that stress distribution transformers and cables and require network reinforcement investment. The regulatory framework for cost allocation of network reinforcement driven by EV charging — specifically, the question of whether EV charging customers should pay the incremental network reinforcement cost attributable to their charging behaviour, or whether this cost should be socialised across all consumers through the general distribution tariff — is an important and unresolved issue in distribution tariff design. SERCs are developing their approaches to this question, informed by the experience of regulators in Europe and North America who have already grappled with the network reinforcement cost allocation challenge as EV penetration has grown in those jurisdictions.

S.9 Green Hydrogen: Regulatory Framework and Legal Dimensions

Green hydrogen — hydrogen produced through the electrolysis of water using electricity generated from renewable sources — is a strategic priority of the Government of India's energy policy, reflected in the National Green Hydrogen Mission (NGHM) launched in January 2023. The NGHM sets ambitious targets for the production of green hydrogen and its use in industrial applications including fertiliser production, refining, steel making, and (potentially) transportation. The achievement of these targets will require massive investments in both renewable electricity capacity (to power the electrolysers) and green hydrogen production infrastructure (including electrolyser manufacturing, compression and storage systems, and transmission and distribution pipelines).

The regulatory interface between the electricity sector and the green hydrogen sector is multi-dimensional. Green hydrogen electrolysers are large electricity consumers, and their procurement of electricity under the existing electricity regulatory framework raises questions about: the applicable category of electricity supply (whether electrolysers should be classified as industrial consumers, captive consumers, or a distinct category); the applicable tariff for electricity used in electrolysis (including whether electrolysers should be eligible for green energy open access at the 100 kW threshold of the 2022 Green Energy Open Access Rules, or whether a higher threshold should apply given the typically much larger scale of industrial electrolysers); the RPO implications of electricity consumed in electrolysis (whether the green hydrogen producer's electricity consumption counts as renewable consumption for the purposes of its own RPO, or whether it creates an RPO obligation that must be satisfied separately); and the banking arrangements for surplus renewable electricity generated by dedicated RE plants supplying electrolysers (allowing surplus generation during high resource periods to be "banked" in the grid for use during low resource periods when electrolysis operations need to continue despite insufficient RE generation).

The Ministry of New and Renewable Energy has issued guidelines addressing several of these electricity regulatory questions for green hydrogen producers, in consultation with the Ministry of Power and CERC. The guidelines provide that: dedicated RE capacity developed for green hydrogen production is exempt from interstate transmission charges and losses for a specified period, providing a cost advantage for green hydrogen projects using electricity from RE plants connected to the ISTS; green hydrogen producers using open access to procure renewable electricity are eligible for the waiver of transmission charges under the applicable CERC regulations; and the electricity consumed in electrolysis satisfies the RPO obligations applicable to the green hydrogen producer in proportion to the renewable content of the electricity used. These guidelines represent an important regulatory accommodation of the green hydrogen sector's electricity needs, and their incorporation into the formal regulatory framework of CERC and the SERCs is an ongoing process.

S.10 Electricity Regulation and India’s Climate Commitments

India's international climate commitments under the Paris Agreement — including the Nationally Determined Contributions (NDCs) submitted to the UNFCCC, which include targets for the non-fossil fuel share of installed electricity capacity and for the reduction of the emissions intensity of GDP — create a direct linkage between the international law of climate change and the domestic legal and regulatory framework of the electricity sector. The achievement of India's NDC targets in the electricity sector depends on the effective implementation of the renewable energy procurement framework, the RPO mechanism, the competitive bidding framework for clean energy, and the energy storage and grid flexibility regulatory provisions that allow high penetrations of renewable energy to be integrated into the grid without compromising supply reliability.

The enactment of the Energy Conservation (Amendment) Act, 2022 represents a significant expansion of the domestic legal framework for climate action in the energy sector. The amendment extends the Energy Conservation Act, 2001 to cover new areas including: the obligation of large commercial buildings to comply with the Energy Conservation Building Code; the requirement for the Central

Government to notify energy consumption standards for industrial facilities; and most significantly, the Carbon Credit Trading Scheme (CCTS) — India's first domestic carbon market. The CCTS creates a legal framework for the issuance, trading, and retirement of carbon credits representing greenhouse gas emission reductions by covered entities, and is intended to create market-based incentives for emission reduction across the industrial and electricity generation sectors.

The intersection of the CCTS with the electricity sector regulatory framework is significant in several dimensions. Electricity generation from fossil fuels will be subject to greenhouse gas accounting and reporting requirements under the CCTS, and fossil-fuel generators that reduce their emissions intensity below specified baselines may earn carbon credits that can be sold to emitters in other sectors. The CCTS thus creates an additional revenue stream for efficient thermal generators and an additional cost for inefficient ones, affecting the competitive dynamics of the generation market and the economic merit order for electricity despatch. Renewable energy generators who supply electricity to the grid displace fossil-fuel generation and thereby contribute to emission reductions, potentially earning carbon credits that provide additional revenue on top of their electricity tariff — a development that would further improve the economics of renewable energy and accelerate the energy transition.

The regulatory framework for carbon markets in the electricity sector also has implications for electricity tariff regulation. If thermal generators earn carbon credits from efficient operation and sell those credits in the CCTS, the question arises whether the carbon credit revenue should be shared with consumers (by reducing the energy charge recoverable in the tariff) or retained by the generator as an incentive for efficiency improvement. CERC and the SERCs will need to develop principles for the treatment of CCTS-related revenues and costs in electricity tariff regulation, ensuring that the carbon market incentives remain effective while also protecting consumers' interests in affordable electricity supply.

S.11 The Electricity Sector and Insolvency Law

The intersection of the electricity sector regulatory framework with insolvency law has become a matter of pressing practical importance as several large private sector thermal power projects have encountered financial distress and been referred to insolvency proceedings under the Insolvency and Bankruptcy Code, 2016 (IBC). The restructuring of financially distressed electricity sector assets under the IBC raises complex legal questions about the interface between the insolvency framework (which is a central legislation under Entry 9 of the Union List, dealing with bankruptcy and insolvency) and the electricity regulatory framework (which is a concurrent subject under Entry 38 of List III).

The principal questions that arise at the intersection of the IBC and the electricity regulatory framework include: whether the Resolution Professional appointed under the IBC can operate an electricity generating station during the resolution period without obtaining a licence from the relevant Commission; whether the SERC or CERC can exercise its supervisory and enforcement jurisdiction over a generating company that is undergoing insolvency proceedings; whether the PPA between an insolvent generator and a distribution utility can be terminated by the procurer in the event of the generator's insolvency (given that the IBC imposes a moratorium on certain enforcement actions against the insolvent company); and whether the Resolution Plan approved by the Committee of Creditors under the IBC can override or modify the terms of the regulated PPA without Commission approval.

APTEL and the Supreme Court have addressed several of these questions in decisions arising from the insolvency proceedings of specific electricity sector projects. The Supreme Court has held that the IBC's moratorium provisions do not prevent the distribution utility from terminating a PPA if the termination is justified on grounds unrelated to the insolvency (such as persistent non-performance of generation obligations by the generator); but that a purported PPA termination that is in substance a response to the insolvency rather than to legitimate performance failures may be stayed by the moratorium. The Court has also addressed the powers of the Resolution Professional to continue operating the generating station and to collect electricity revenues during the resolution period, holding that these operational powers are necessary for the preservation of the going-concern value of the insolvent electricity asset during the resolution process.

The treatment of electricity sector assets in the IBC framework also raises questions about the regulatory compact. When an insolvent generator is acquired by a new owner through the IBC resolution process, the new owner typically seeks to renegotiate the PPA terms (arguing that the original PPA tariff was part of the financial structure that led to the generator's insolvency and is unsustainable for the new investor). The Commission's response to such renegotiation requests — balancing the interest of the new investor in viable project economics against the interest of consumers in the tariff certainty that the competitive bidding or regulatory tariff process was designed to provide — is a challenging regulatory question that has not yet been definitively resolved.

S.12 Consumer Rights in the Digital Age: New Frontiers

The digitalisation of the electricity sector is creating new dimensions to the relationship between electricity consumers and utilities, with implications for the consumer protection framework under the Electricity Act, 2003. The deployment of smart meters, the development of consumer-facing digital platforms for billing and service management, the emergence of distributed energy resources including rooftop solar and battery storage, and the growth of peer-to-peer electricity trading platforms are all reshaping the nature of the consumer experience in the electricity sector and the regulatory obligations applicable to utilities in relation to their consumers.

Smart meter data — the granular, near real-time consumption data generated by smart meters — creates new questions about data ownership, privacy, and the appropriate use of consumer information by utilities. Electricity consumption data is sensitive personal information that can reveal intimate details about household activity patterns, appliance usage, and lifestyle, and its unauthorised access or misuse could constitute a serious privacy violation. The regulatory framework for smart meter data protection must address: who owns the smart meter data (the consumer or the utility); who may access the data and under what conditions; what uses of the data are permitted for billing, network planning, and commercial analytics; and how the data must be secured against cyber threats. The Personal Data Protection Bill (in various iterations under parliamentary consideration) and the recently enacted Digital Personal Data Protection Act, 2023 provide the general legal framework for data protection that is applicable to smart meter data, but the electricity sector-specific implications of these data protection requirements need to be addressed by CERC and the SERCs in their metering regulations.

The development of prosumer — consumers who also generate electricity from rooftop solar or other distributed generation and feed surplus electricity back into the grid — creates a new category of electricity consumer-producer relationship that the traditional regulatory framework was not designed to accommodate. The net metering regulations issued by SERCs under the guidance of the Ministry of New and Renewable Energy enable prosumers to offset their consumption against their generation on a net basis, with the distribution utility billing only the net consumption (or crediting the net generation) on a monthly or annual basis. The PM Surya Ghar Muft Bijli Yojana, launched in 2024, targets the installation of rooftop solar systems in one crore residential households with government subsidies, potentially creating a very large population of prosumers whose regulatory treatment will need to be systematically addressed by the SERCs.

Peer-to-peer (P2P) electricity trading — in which prosumers with surplus generation can sell electricity directly to neighbouring consumers over the distribution network without going through the distribution licensee as intermediary — is an emerging concept that several countries are beginning to implement on a pilot basis. In the Indian context, P2P electricity trading raises profound regulatory questions: whether the distribution licensee's natural monopoly in the distribution of electricity extends to blocking P2P transactions between consumers connected to its network; what charges should be payable for the use of the distribution network in P2P transactions; and how the regulatory framework should evolve to accommodate P2P trading while protecting the financial viability of the distribution utility whose network is used for such transactions. These questions are at the frontier of electricity regulatory innovation globally, and India's approach to them will shape the evolution of the consumer-facing segment of the electricity market as distributed energy resources proliferate.

The future of electricity consumer regulation in India must grapple with the fundamental tension between the traditional model of the electricity consumer as a passive recipient of regulated monopoly supply and the emerging model of the active energy consumer who generates electricity, manages flexible loads, participates in demand response programmes, stores energy in on-site batteries, and potentially trades electricity with neighbours and the market. The regulatory framework must evolve to accommodate this transition from passive consumer to active market participant, while ensuring that the benefits of technology and market innovation are accessible to all segments of the population rather than being confined to affluent households and large commercial consumers. This is the defining challenge for electricity consumer regulation in India in the coming decades, and the Electricity Act, 2003's framework of independent regulatory commissions with broad discretionary authority to adapt their regulatory instruments to evolving market conditions provides the institutional architecture within which this challenge can be addressed.

> **Key Takeaways — The Electricity Act, 2003 at Twenty Years**
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> The Electricity Act, 2003 established the legal architecture for the transformation of the Indian electricity sector from a state-controlled, vertically integrated, and regulation-light framework to a competitive, independently regulated, and commercially oriented market. Two decades after its enactment, the Act's principal achievements include: the creation of independent regulatory institutions (CERC, SERCs, APTEL) with genuine authority and demonstrated credibility; the de-licensing of electricity generation enabling massive private investment; the competitive procurement framework under Section 63 driving unprecedented cost reductions in renewable energy; and the mandatory open access framework enabling large consumers to access competitive supply. The principal ongoing challenges include: the financial stress of state distribution utilities; the persistence of below-cost agricultural tariffs and distortionary cross-subsidies; the uneven quality of regulatory oversight across states; and the emerging regulatory challenges of the energy transition including renewable integration, storage, EVs, and digital technology. The legal framework's continued evolution through legislative amendment, regulatory innovation, and judicial development will determine its adequacy for the demands of India's electricity sector through its next phase of transformation.