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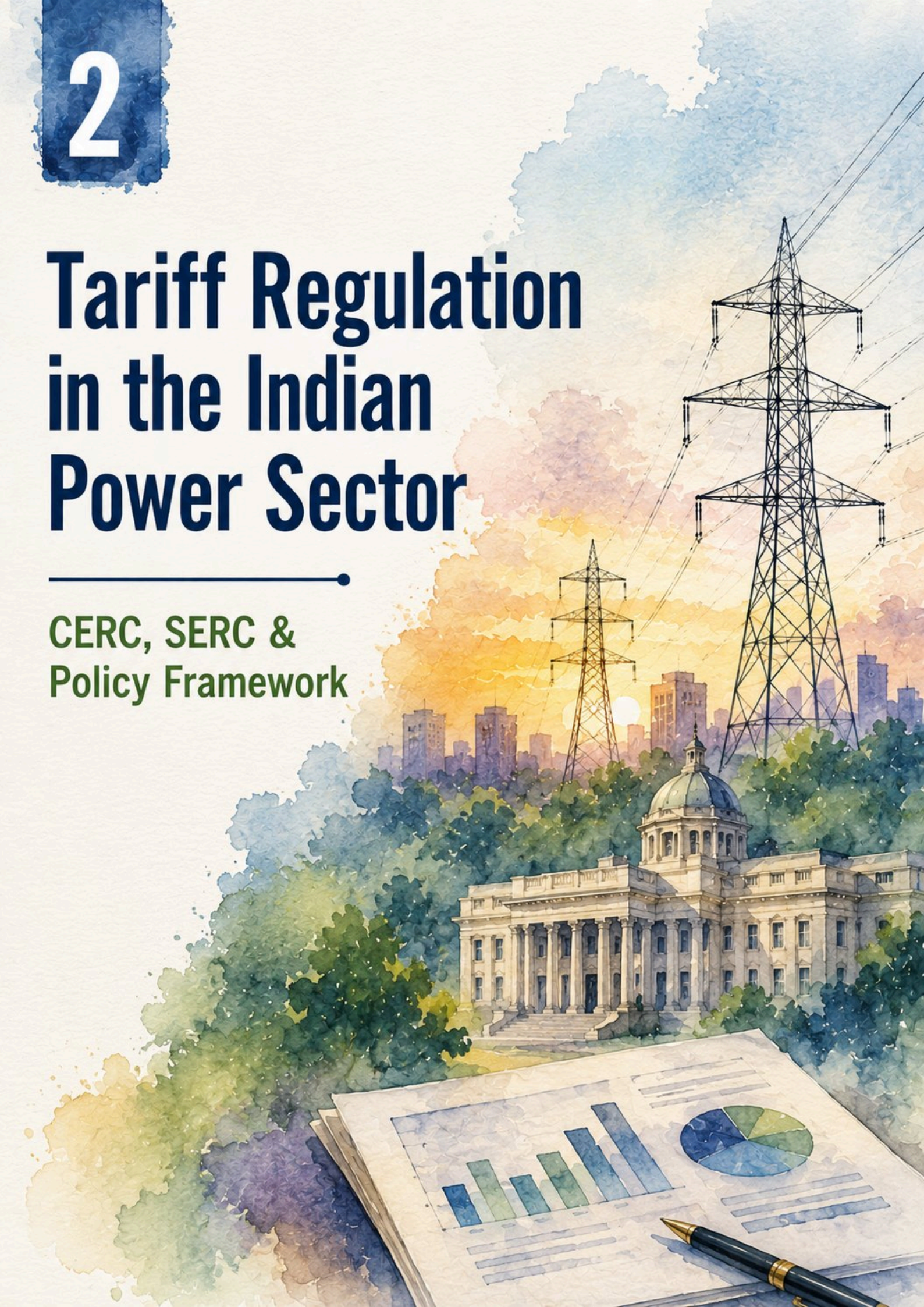
Tariff Regulation in the Indian Power Sector

CERC, SERC & Policy Framework



BHATT & JOSHI ASSOCIATES — INDIAN POWER SECTOR LEGAL SERIES

Tariff Regulation

Economic Principles & Regulatory Mechanisms

Booklet II of VI

Bhatt & Joshi Associates

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CHAPTER ONE

Economic Principles of Electricity Tariff Regulation

Natural Monopoly, Cost Recovery, Ramsey Pricing, and the Indian Framework

Electricity tariff regulation is grounded in economic theory that explains why markets fail to produce efficient outcomes in network industries and how regulatory instruments can replicate competitive market outcomes. Understanding these theoretical foundations is essential for practitioners who must interpret and apply the regulatory framework.

1.1 Natural Monopoly and the Rationale for Regulation

The economic rationale for electricity tariff regulation derives from the natural monopoly characteristics of electricity transmission and distribution networks. A natural monopoly exists when the technology of production is characterised by economies of scale so pervasive that one firm can supply the entire market at lower total cost than two or more competing firms. In such conditions, the free entry of multiple competing firms would be economically wasteful: each firm would duplicate infrastructure, none would achieve the minimum efficient scale of operation, and the average cost of supply would be higher than in a monopoly structure. The natural monopoly in electricity networks arises from the large sunk costs of network infrastructure (transmission towers and cables, distribution transformers and poles, substations and switchgear), the economies of density (the

cost per consumer falls as the number of consumers connected to a given network increases), and the impossibility of consumers switching between competing parallel networks without prohibitive transaction costs.

An unregulated natural monopoly has both the incentive and the ability to set prices above the competitive level, extracting monopoly rents at the expense of consumers. The profit-maximising price for an unregulated monopoly is determined by equating marginal revenue with marginal cost: at this price, the monopoly produces less than the socially optimal quantity of output (since the price exceeds marginal cost, there are transactions that would be mutually beneficial but do not take place) and earns a producer surplus that exceeds the competitive level. The resulting deadweight loss — the value of the transactions foregone due to the above-competitive price — represents a social welfare loss. The objective of economic regulation in natural monopoly industries is to eliminate or substantially reduce this deadweight loss by constraining the monopolist's pricing to levels closer to the competitive level, while ensuring that the monopolist can recover its costs and earn a sufficient return to sustain its investment in the regulated infrastructure.

The two fundamental approaches to achieving the regulatory objective are rate-of-return (cost-of-service) regulation and incentive regulation. Under rate-of-return regulation, the regulator sets prices at the level that allows the utility to recover its prudently incurred costs plus a fair return on its invested capital. Under incentive regulation (particularly price-cap regulation), the regulator sets a price ceiling that is indexed to an efficiency target (typically the inflation rate minus an assumed productivity improvement factor, or RPI-X in the terminology originated in British utility regulation), allowing the utility to retain the financial benefit of cost reductions below the price cap but requiring it to reduce prices for consumers over time as efficiency improvements reduce costs. Each approach has advantages and disadvantages: cost-of-service regulation provides revenue certainty but weak cost reduction incentives, while incentive regulation provides strong cost reduction incentives but may create quality service trade-offs if not properly designed.

1.2 The Cost of Service Methodology: Components and Application

The cost of service (CoS) methodology, the dominant approach to electricity tariff regulation in India, involves a detailed specification of the costs that the regulated utility is entitled to recover through its tariffs, the permitted return on investment, and the tariff levels necessary to generate the approved revenue. The application of the CoS methodology requires the regulator to: identify the assets constituting the regulated utility's rate base (the asset base on which the return on investment is computed); determine the allowable capital costs for new investments; specify the allowed operating expenditure levels; determine the appropriate rate of return on the rate base; compute the annual revenue requirement as the sum of depreciation, return on capital, and operating expenditure; and translate the aggregate revenue requirement into specific tariff schedules for different consumer categories.

The determination of the rate base is particularly important because it directly determines the return on investment allowed to the utility: a larger rate base means a higher annual return and higher tariffs. The prudency standard — which requires that only capital expenditure that is prudent from the perspective of serving consumers at minimum cost qualifies for inclusion in the rate base — is the primary tool used by regulators to prevent utilities from inflating their rate base through extravagant or inefficient capital spending. CERC and the SERCs have developed extensive prudency review frameworks for capital expenditure, examining each major investment project against criteria of technical necessity, commercial reasonableness, and consistency with the utility's approved capital expenditure plan.

The allowed operating expenditure covers the utility's ongoing costs of providing regulated services, including employee costs, repair and maintenance, administrative and general expenses, and contracted services. Regulators typically specify normative O&M expense trajectories rather than allowing actual incurred expenses, to preserve the efficiency incentive: if the utility achieves O&M costs below the normative level, it retains the saving; if costs exceed the normative level, it bears the excess. The normative O&M expense levels are set based on benchmarking analysis of comparable utilities in India and internationally, with appropriate adjustments for the specific characteristics of the regulated entity.

1.3 Ramsey Pricing and Tariff Structure

The theoretical framework of Ramsey pricing provides the welfare-maximising approach to recovering fixed costs through electricity tariffs when a utility faces a heterogeneous consumer population with different demand elasticities. The Ramsey pricing rule states that the welfare-maximising mark-up above marginal cost for each consumer category should be inversely proportional to the price elasticity of demand for that category: consumers whose demand is inelastic (insensitive to price changes) should face higher mark-ups, while consumers whose demand is elastic (sensitive to price changes) should face lower mark-ups closer to marginal cost. The rationale is that the deadweight loss from raising prices above marginal cost is minimised when the price increase is concentrated on consumers who will reduce their consumption least in response to higher prices.

While Ramsey pricing is not directly implemented by Indian electricity regulators (who face information constraints in estimating demand elasticities and political constraints in designing tariffs based on willingness-to-pay principles), the underlying logic informs several features of Indian tariff design. Industrial and large commercial consumers, whose demand tends to be more elastic than that of small domestic consumers (because they have greater scope for self-generation, energy efficiency investment, and demand management in response to higher tariffs), generally face lower tariffs relative to the average cost of supply than residential consumers in the medium and upper consumption brackets. This pattern is consistent with the Ramsey principle of applying smaller mark-ups to elastic demand, though the actual tariff differentials in practice reflect political economy factors as much as efficiency principles.

1.4 Two-Part Tariffs and Efficient Pricing

Two-part tariffs — tariff structures combining a fixed charge (independent of consumption) with a variable energy charge (proportional to consumption) — are the standard approach to efficient pricing for electricity consumers in India and globally. The economic rationale for two-part tariffs is that: the fixed charge recovers the portion of the utility's costs that do not vary with consumption (primarily the fixed costs of the distribution network), while the variable energy charge reflects the marginal cost of electricity supply (primarily fuel and purchased power costs); and the separation of fixed and variable cost recovery preserves the efficiency of the energy price signal for consumption decisions, since consumers pay the marginal cost of their electricity consumption in the energy charge while the fixed charge is a lump-sum payment that does not affect the marginal decision to use more or less electricity.

The practical design of two-part tariffs for Indian electricity consumers involves several challenging trade-offs. For domestic consumers, a high fixed charge relative to the energy charge improves cost recovery efficiency (since domestic consumers' consumption is relatively insensitive to the energy charge level) but may reduce equity (since lower-income households pay proportionally more of their electricity bill as a fixed cost). Conversely, a low fixed charge with a high energy charge is more

equitable (lower-income households with lower consumption pay less) but may encourage meter tampering or evasion of the fixed charge. Indian SERCs have generally opted for relatively low fixed charges and relatively high energy charges for domestic consumers, reflecting the equity preference and the practical difficulty of enforcing fixed charges on a large, dispersed, and low-income consumer base.

1.5 Marginal Cost Pricing vs Average Cost Recovery

The fundamental tension in electricity tariff design between the efficiency objective (tariffs should equal marginal cost) and the cost recovery objective (tariffs must cover total average costs) has been the subject of extensive analysis in the economics and regulatory literature. In the electricity sector, this tension manifests in the "decreasing block tariff" problem: electricity distribution networks have high fixed costs relative to variable costs, meaning that average costs exceed marginal costs. Pricing at marginal cost therefore leaves a revenue shortfall that must be covered through fixed charges or through tariffs above marginal cost for some consumer categories.

Indian SERCs have generally addressed this tension through the use of multi-part tariffs that combine fixed charges, energy charges, and demand charges in varying proportions for different consumer categories. Large industrial and commercial consumers, who have more sophisticated metering and billing capabilities and whose consumption has a more predictable structure, typically face three-part tariffs with separate fixed, energy, and demand charge components. Small commercial and domestic consumers typically face simpler two-part tariffs (fixed plus energy) or even single-part tariffs (energy charge only) for the lowest consumption slabs. The appropriate mix of tariff components for each consumer category is one of the most technically complex and commercially consequential decisions that SERCs make in their periodic tariff orders.

1.6 The Tariff Policy: Legal Binding Force and Economic Content

The Tariff Policy notified by the Central Government under Section 3(1) of the Electricity Act, 2003 represents the Central Government's authoritative statement of the economic principles that should guide electricity tariff regulation in India. Its binding legal character — derived from the requirement in Section 61 that the Appropriate Commission shall be guided by it in determining tariffs — gives the Tariff Policy a significance in the Indian electricity regulatory framework that goes beyond that of an ordinary policy document: it functions as a bridge between the broad economic principles established in the Act and the specific tariff determinations made by CERC and the SERCs in individual regulatory proceedings.

The Tariff Policy's principal economic provisions address: the principle that tariffs should be based on the cost of supply, computed on a utility-specific basis as the full cost of generation, transmission, and distribution applicable to the relevant consumer category in the relevant utility's service territory; the requirement that cross-subsidies be progressively reduced and eventually eliminated, with tariffs for each consumer category required to fall within a band of plus or minus 20 per cent of the average cost of supply for that category within a defined timeframe; the principle that the tariff structure should provide efficient price signals for electricity consumption decisions, including through the use of multi-part tariffs for large consumers and time-of-use pricing where technically feasible; and the requirement that any subsidies for specific consumer categories be transparent, targeted, and time-bound rather than being hidden in the tariff structure through cross-subsidisation.

1.7 Affordability and the Social Dimension of Tariff Regulation

The social dimension of electricity tariff regulation — the obligation to ensure that electricity remains affordable for lower-income consumers while covering costs for the utility — creates an ongoing tension with the efficiency objective of cost-reflective pricing. This tension is not unique to India; regulatory authorities worldwide grapple with the need to reconcile economic efficiency with social policy objectives in the design of tariffs for essential services. The policy choice between efficiency and equity in tariff design ultimately reflects the normative priorities of the relevant society, expressed through the political process and embodied in the policy framework that the regulatory commission is required to implement.

India's historical approach to the social dimension of tariff regulation has relied heavily on cross-subsidisation — setting tariffs below cost for "social" consumer categories (domestic at lower consumption levels, agricultural) and above cost for "commercial" consumer categories (industrial, large commercial) — as the primary instrument for ensuring electricity affordability. This approach is administratively simple (it requires no separate means-testing of consumers or direct payment of subsidies) but economically inefficient (it distorts price signals for all consumer categories, not just the targeted beneficiaries) and increasingly financially unsustainable (as the cross-subsidy burden has grown to a level that threatens the financial viability of distribution utilities in several states).

The evolution of the tariff regulatory framework towards more targeted and transparent subsidy mechanisms — including the Direct Benefit Transfer mechanism proposed in the Electricity Amendment Bill and the Section 65 payment mechanism in the existing law — reflects the growing recognition that cross-subsidisation is an inefficient and unsustainable instrument for electricity affordability policy. The challenge is to transition from the current cross-subsidy system to more targeted alternatives in a politically manageable way that protects genuinely vulnerable consumers while reducing the financial distortions imposed by blanket below-cost tariffs for large consumer categories.

1.8 Benchmarking and Regulatory Efficiency

Benchmarking — the comparison of a regulated utility's performance against peer utilities or against normative standards — is an important tool for incentive regulation that CERC and the SERCs use to set efficiency targets and efficiency benchmarks for regulated utilities. Benchmarking serves both an informational function (providing the regulator with evidence about achievable performance levels) and an incentive function (creating financial consequences for utilities that perform below the benchmarked efficiency frontier).

CERC's benchmarking of central generating stations uses normative heat rate standards derived from the design performance specifications of generating units and from the actual performance of the best-performing units of comparable technology and vintage in India. These heat rate benchmarks are updated periodically to reflect improvements in generating unit performance achievable through technology upgrades, operational improvements, and fuel quality optimisation. Units that achieve heat rates better than the benchmark earn additional revenue from the fuel cost saving, creating a direct financial incentive for heat rate improvement programmes.

The benchmarking of distribution utility performance by SERCs is more complex given the heterogeneity of distribution systems across India in terms of consumer mix, network topology, urbanisation level, and legacy infrastructure condition. SERCs use multiple benchmarking approaches including: cost per unit benchmarking (comparing the distribution utility's cost per unit of

electricity delivered against peer utilities after adjusting for structural differences in service territory characteristics); AT&C loss benchmarking (comparing the utility's distribution loss level against best-practice distribution utilities in India and internationally, with adjustments for metering quality and consumer mix); and capital expenditure benchmarking (comparing the utility's per-unit capital expenditure against comparable utilities to identify outliers that may indicate imprudent investment or investment shortfalls).

1.9 Network Pricing Efficiency

The pricing of access to electricity networks — transmission and distribution — raises specific efficiency questions that differ from those applicable to the pricing of electricity supply. Network pricing must: recover the total cost of the network (including the large fixed capital costs of network infrastructure); provide efficient price signals to network users about the cost of their specific usage patterns; and not discriminate between similarly situated network users in violation of the non-discrimination principles of the regulatory framework.

The efficiency of network pricing is assessed against several criteria. First, the locational efficiency criterion: do network prices reflect the spatial variation in network costs, providing signals for efficient location decisions by generators and large consumers? Second, the temporal efficiency criterion: do network prices reflect the time-varying cost of network use, providing signals for efficient load management decisions? Third, the investment efficiency criterion: do network prices provide sufficient and appropriate signals for investment in network expansion and reinforcement?

Current Indian network pricing practices score unevenly against these efficiency criteria. The postage stamp approach to ISTS transmission charges (applicable to renewable energy generators) does not reflect locational cost differences, providing no price signal for efficient location of new renewable energy generation within the geography of the national grid. The distribution wheeling charge methodology similarly does not typically reflect either the locational or the temporal variation in distribution network costs, providing limited efficiency signals for the location and management of consumer loads within the distribution system. The development of more locationally and temporally differentiated network pricing, facilitated by smart metering infrastructure and advanced network monitoring systems, is a long-term direction of travel for Indian electricity network pricing reform.

1.10 International Regulatory Frameworks: Comparative Perspective

The international experience of electricity tariff regulation provides a rich source of insights for the continuing development of India's regulatory framework. Several key models from different regulatory traditions are particularly relevant.

The United Kingdom's RPI-X price cap regulation, introduced by the energy regulator Ofgem (previously Offer and Ofgas) in the 1990s, established an influential model of incentive regulation that has been widely adopted and adapted in other jurisdictions. Under RPI-X, the regulator sets a price cap for the regulated utility that is adjusted annually by the general rate of price inflation (RPI or CPI) minus an efficiency factor X, which represents the regulator's estimate of the productivity improvement that an efficient utility should be able to achieve over the regulatory period. The price cap creates a strong incentive for cost reduction: the utility bears the full financial benefit of any costs savings it achieves, since the cap does not adjust downward in response to lower actual costs. At the end of the regulatory period, the regulator resets the cap based on a comprehensive review of the utility's actual

costs and projected future costs, ensuring that persistent cost reductions are eventually passed through to consumers.

Australia's National Electricity Market (NEM) provides an example of a competitive electricity market with regulated network access. The Australian Energy Regulator (AER) regulates the transmission and distribution networks using a building block approach to revenue determination that is similar in principle to India's cost-of-service framework but with important differences in the treatment of the allowed rate of return (which is computed using a WACC framework based on market-observed risk parameters), capital expenditure assessment (which uses an ex ante assessment of required capital expenditure rather than ex post prudency review), and efficiency benchmarking (which uses econometric models to compare each network's cost performance against a reference efficient network). The Australian experience of managing the high penetration of rooftop solar generation and the associated challenges for distribution network planning and tariff design is particularly relevant for India as rooftop solar penetration grows under the PM Surya Ghar scheme.

CHAPTER TWO

CERC Tariff Determination: Methodology and Practice

Capital Costs, Annual Fixed Charges, Energy Charges, and Regulatory Jurisprudence

The CERC tariff regulatory methodology for central generating stations and ISTS assets is a comprehensive and highly specified framework that balances cost recovery for regulated utilities with incentives for operational efficiency and consumer interest protection. This chapter examines the methodology in depth.

2.1 Structure of CERC Tariff Regulations

CERC's Terms and Conditions of Tariff Regulations have been issued and periodically revised to cover successive regulatory periods since CERC's establishment in 1998. The most recent comprehensive revision covers the regulatory period 2019–2024, with the next revision for 2024–2029 under preparation at the time of writing. Each set of Regulations specifies: the norms and parameters applicable to tariff determination for central generating stations (thermal, hydro, nuclear, and renewable energy) and the ISTS; the methodology for computing the Annual Fixed Charge (AFC) and the Energy Charge Rate (ECR); the normative performance benchmarks (NAPAF/NAPLF, heat rates, auxiliary consumption); the mechanism for incentive payments for above-normative availability and penalty deductions for below-normative availability; the provisions for the adjustment of approved capital cost; and the procedures for annual true-up and revision of tariff during the regulatory period.

The Tariff Regulations are supplemented by CERC's model PPAs (Power Purchase Agreements) for central generating stations, which are standard form agreements developed by CERC that incorporate the key tariff provisions and payment security requirements approved by the Commission. The use of model PPAs reduces transaction costs in the negotiation of PPAs between generating companies and distribution utilities, and ensures that the key regulatory provisions are consistently reflected across all PPAs for central generating stations. CERC reviews and updates its model PPAs periodically to reflect changes in the tariff framework and to address issues that have arisen in the implementation of existing model PPAs.

2.2 Capital Cost: Normative Benchmarks and Scrutiny

The capital cost eligible for tariff recovery under CERC's regulatory framework is determined through a combination of normative benchmark costs (for new projects developed within the applicable benchmark cost range) and specific scrutiny of the actual incurred costs (for projects whose costs deviate significantly from the benchmark or for projects seeking revision of their approved capital cost). The normative capital cost benchmarks specified in the Regulations are based on CERC's assessment of the capital cost achievable by an efficiently managed project of the relevant technology and capacity, drawing on the experience of projects recently developed in India and comparable projects in other developing economies.

For thermal generating stations, the normative capital cost benchmark is expressed in Rs. per MW of installed capacity, with separate benchmarks for different categories of coal-based stations (pit-head, imported coal, blended) and gas-based stations. The benchmark costs are revised at each new regulatory period to reflect changes in equipment prices, construction costs, and financing costs since the previous revision. For hydro generating stations, normative capital cost benchmarks are more difficult to

specify given the highly site-specific nature of hydro project costs; instead, CERC conducts project-specific scrutiny of the capital cost for each hydro project, reviewing the project's detailed cost estimates against comparable project costs and the CEA's techno-economic concurrence documentation.

2.3 Annual Fixed Charge: Components and Computation

The Annual Fixed Charge (AFC) for a central generating station is computed as the sum of five components: depreciation, return on equity (RoE), interest on long-term loans, interest on working capital, and operation and maintenance (O&M) expenses. Each of these components is computed using specified formulae and parameters prescribed in the Tariff Regulations.

Depreciation is computed on the gross fixed assets (i.e., on the total capital cost including the debt and equity components) using the straight-line method (SLM) at the rates prescribed in the Regulations for different asset categories. The depreciation rates are structured to provide higher depreciation in the early years of operation (matching the higher debt servicing obligations during the loan repayment period) and lower depreciation in later years after the loan is substantially repaid. The total depreciation recovered over the useful life of the asset is capped at 90 per cent of the capital cost, with the remaining 10 per cent representing the residual value of the asset.

Return on equity is computed on the equity portion of the capital cost at the post-tax RoE rate specified in the Regulations. The equity portion is normalised at 30 per cent of the approved capital cost (the balance 70 per cent being assumed to be financed by debt), regardless of the actual debt-equity mix of the project's financing. This normalised debt-equity assumption avoids regulatory distortions that could arise if utilities were rewarded for high equity content (which would increase the RoE base and therefore the AFC) or penalised for high debt content (which would reduce the RoE base). The post-tax RoE rate has been set at 15.5 per cent per annum in recent CERC Tariff Regulations, representing the regulator's assessment of the fair return required to attract equity capital to regulated electricity infrastructure.

Interest on long-term loans is computed on the outstanding loan balance at the applicable weighted average interest rate, which is determined by CERC based on the actual financing terms of the project's approved capital cost. The loan repayment schedule, and therefore the trajectory of the AFC over the regulatory period, reflects the actual loan repayment terms negotiated by the generating company. CERC reviews the loan terms to ensure that they are consistent with the prevailing market terms for infrastructure project finance and that any unusually favourable or unfavourable terms reflect genuine market conditions rather than related-party transactions or financial engineering designed to manipulate the AFC.

2.4 Energy Charge Rate: Fuel Cost Components

The Energy Charge Rate (ECR) for a thermal generating station is computed using the formula: ECR = (Normative Heat Rate × Applicable Fuel Price) / (1 - Normative Auxiliary Consumption), expressed in Rs. per kWh. Each element of this formula involves specific regulatory determinations that significantly affect the tariff payable by distribution utility procurers.

The normative heat rate (NHR) is the primary efficiency benchmark for thermal generating stations, expressing the quantity of heat required from fuel to generate one unit of electricity. It is typically expressed in kCal/kWh (kilocalories of heat per kilowatt-hour of electricity generated). The NHR specified in CERC's Tariff Regulations represents the performance achievable by an efficiently operated generating unit of the relevant technology, size, and vintage at the normative loading level. A generating unit

operating at a heat rate better than the NHR consumes less fuel per unit of generation, earning the fuel cost saving as additional profit; a unit operating at a worse heat rate bears the additional fuel cost internally.

The normative heat rate norms have been a subject of sustained regulatory and legal contest between generating companies (which argue for higher normative heat rates that allow more fuel cost recovery per unit of generation) and procurers (which argue for lower normative heat rates that reduce the ECR and therefore the electricity tariff payable by distribution utilities). CERC has addressed this contest through a systematic review of generating unit performance data and a progressive tightening of NHR norms over successive regulatory periods, reflecting the improvement in actual operating performance achievable through technology improvement, better fuel quality management, and operational best practices.

2.5 Incentive Structure: Availability and Performance

The availability-based tariff (ABT) framework creates the primary incentive mechanism within CERC's cost-based tariff system. Under the ABT framework, the AFC is payable at the full normative level only if the generating station achieves the Normative Annual Plant Availability Factor (NAPAF) — the minimum percentage of the year for which the station must be available to generate electricity, whether or not it is actually despatched. If the station's availability falls below the NAPAF, the AFC is reduced in proportion to the shortfall; if availability exceeds the NAPAF, an incentive payment is made to the generator at the rate of 0.5 per cent of the AFC per percentage point of excess availability, up to a specified maximum.

The availability measurement is based on the station's declared availability, communicated to the RLDC on a day-ahead basis, rather than on actual generation. This is appropriate because the AFC is a capacity payment designed to compensate the generator for maintaining capacity available to the grid, regardless of whether it is called upon to generate. The distinction between availability and generation is central to the ABT framework: the generator receives the AFC if it is available; it receives the ECR only for actual energy generated in response to despatch instructions from the RLDC.

2.6 Transmission Tariff Methodology for ISTS

The transmission tariff for ISTS assets is determined by CERC through a project-specific tariff order for each transmission element, based on the same cost-of-service principles applied to generating stations. PGCIL (as CTU) and private transmission licensees file tariff petitions for each transmission project, specifying the approved capital cost, the financing structure, and the applicable O&M expense norms, and CERC determines the annual transmission charge (ATC) for each project through a formal regulatory proceeding.

The sharing of the total ISTS annual transmission charge among users (distribution utilities, open access consumers, and generators) is governed by the CERC (Sharing of ISTS Charges and Losses) Regulations. The current methodology uses a "postage stamp" approach for renewable energy generators — under which RE generators pay a fixed charge per MW of contracted generation capacity regardless of their physical location — and a "flow-based" methodology for conventional generators and bulk consumers. The postage stamp approach for RE generators has been a deliberate policy choice to promote renewable energy development by reducing the locational cost risk for RE developers: under a locational pricing approach, RE generators in remote resource-rich areas might face very high transmission charges reflecting the cost of the long transmission lines needed to connect their output to load centres, making their projects commercially unviable.

2.7 Multi-Year Tariff for Central Generating Stations

CERC's tariff determination for central generating stations follows a multi-year framework in which the tariff is fixed for the full 25-year term of the PPA at the levels determined in the initial tariff order, subject to annual adjustments for changes in variable costs (fuel prices) and periodic true-up adjustments for changes in approved capital cost (arising from additional capital expenditure). This long-term tariff fixity is essential for project finance: debt providers need certainty about the generating company's future revenues to assess the project's debt serviceability, and the tariff order provides the primary basis for the project's bankability.

The challenge of long-term tariff fixity is that it may allow generating companies to earn excessive returns if their actual costs fall significantly below the approved levels (for instance, due to lower-than-expected fuel costs or higher-than-expected equipment efficiency), while conversely it may strand the generating company if its actual costs significantly exceed the approved levels (for instance, due to cost overruns in construction or higher-than-expected fuel prices after the PPA is signed). CERC addresses this challenge through the true-up mechanism: periodic review of actual costs against approved costs, with adjustments to the tariff to reflect material variations. The true-up mechanism does not provide full insurance against cost variations (the generator bears the risk of efficiency shortfalls below the normative parameters) but ensures that systematic under-recovery or over-recovery arising from changes in approved capital costs is corrected over time.

2.8 Nuclear Power Tariff Regulation

Nuclear electricity generation presents special regulatory considerations that distinguish it from the thermal and hydro generation frameworks. Nuclear Power Corporation of India Limited (NPCIL) operates India's fleet of nuclear generating stations, which are regulated by CERC for tariff purposes under the same basic cost-of-service framework as other central generating stations. However, the nuclear tariff framework includes several specific provisions reflecting the distinctive economics and risk profile of nuclear generation.

The capital cost of nuclear generating stations is significantly higher per MW of installed capacity than for coal-based thermal stations, reflecting the cost of the nuclear safety systems (including multiple redundant cooling systems, containment structures, and radiation monitoring and protection systems), the cost of fuel (nuclear fuel fabrication from uranium or thorium is a specialised and relatively expensive process), and the cost of waste management and eventual decommissioning of the nuclear facility. CERC's normative capital cost framework for nuclear stations is accordingly higher than for thermal stations, and the AFC for a nuclear station reflects the higher capital cost base.

2.9 Tariff Determination Disputes: Major Categories

The CERC tariff determination process generates a substantial volume of regulatory and legal disputes, reflecting the complexity of the methodology, the large financial stakes involved in tariff decisions for central generating stations with contracts worth tens of thousands of crore rupees over their 25-year operating life, and the divergent interests of generators (who prefer higher approved capital costs, higher normative heat rates, and higher return on equity) and procurers (who prefer lower approved costs and tighter efficiency benchmarks). The major categories of tariff disputes that come before CERC and APTEL include the following.

Capital cost inclusion disputes: these arise when CERC disallows specific capital cost items from the approved tariff base on grounds of imprudence, cost being beyond normative parameters, or classification as non-capital expenditure. Generators challenge these disallowances arguing that the relevant costs were necessarily incurred in the development and construction of the generating station and that their exclusion violates the regulatory compact of full prudent cost recovery. Major capital cost items that have been the subject of disputes include: interest during construction arising from construction delays; costs of replacement of equipment that failed during the construction period; costs of connecting infrastructure such as approach roads, water supply, and coal handling facilities; and the cost of environmental compliance infrastructure.

Normative parameter disputes: these arise when CERC determines the normative heat rate, normative availability factor, or normative O&M expense at levels that the generator argues are unachievable given the specific characteristics of the generating station. Generators argue that CERC's normative parameters are based on average performance across a fleet of generating stations and do not adequately reflect the specific design constraints, fuel characteristics, or operating environment of their particular generating units. Procurers argue that the normative parameters should represent best-practice performance achievable by an efficiently operated generating station, not average performance.

2.10 Section 63 Adoption Proceedings

The tariff adoption proceedings conducted by CERC under Section 63 for power procured through competitive bidding follow a different and simpler process than the cost-based tariff determination under Section 62. In Section 63 proceedings, the Commission's role is essentially to verify the procedural integrity of the bidding process and to satisfy itself that there are no patent irregularities that would cast doubt on the validity of the competitively discovered tariff. CERC does not examine the underlying cost structure of the successful bidder's project or evaluate whether the tariff discovered is economically reasonable in terms of project economics; these matters have been determined by the competitive process itself.

The standard CERC adoption proceeding under Section 63 involves: the procuring entity filing a petition with CERC enclosing the executed PPA, the RfS document and its amendments, the bid evaluation report showing the prices received from all qualified bidders and the basis for selecting the lowest bidder, and a declaration that the bidding process was conducted in accordance with the applicable Central Government guidelines. CERC examines the submitted documents, invites objections from the procurer's consumers and other interested parties, and issues an order adopting the tariff if satisfied that the process was properly conducted. Where irregularities or deviations from the guidelines are found, CERC may decline to adopt the tariff or may require corrections or adjustments as a condition of adoption.

CHAPTER THREE

State-Level Tariff Regulation: Methodology and Practice

SERC Distribution Tariff Determination, MYT Framework, and Consumer Category Design

State Electricity Regulatory Commissions bear the primary responsibility for the retail electricity tariffs that directly affect millions of consumers across India. This chapter examines the methodology and practice of distribution tariff regulation at the state level.

3.1 Aggregate Revenue Requirement: Framework and Components

The Aggregate Revenue Requirement (ARR) of a distribution utility is the total revenue that the utility is entitled to recover from its consumers through regulated tariffs in a given year. The ARR is the foundation of the distribution tariff determination process: once the Commission determines the approved ARR, the retail tariff schedule is designed to generate revenues equal to the approved ARR through charges on different consumer categories in proportions consistent with the applicable cost allocation and cross-subsidy provisions. The difference between the ARR and the revenues actually collected (the "revenue gap") must be addressed in subsequent tariff proceedings through adjustments to approved tariffs or accumulated in a regulatory asset balance that is carried forward for recovery in future periods.

The components of the ARR for a typical state distribution utility include: power purchase cost (the dominant component, comprising the cost of electricity procured from central and state generating stations, independent power producers, and renewable energy generators under long-term and short-term PPAs); transmission and SLDC charges (the charges payable to the ISTS and the state transmission utility for transporting the procured electricity from generating stations to the distribution network); wheeling cost (the cost of own distribution network, comprising O&M expenses, depreciation, interest, and return on equity for distribution assets); employee cost and other O&M expenses; depreciation on distribution assets; interest on outstanding borrowings for distribution investment; and return on equity on the distribution utility's regulated asset base.

3.2 Power Purchase Cost: Determination and Management

The cost of power purchase is typically the largest single component of a distribution utility's ARR, constituting 60-70 per cent or more of total costs in many states. The determination and management of power purchase costs is therefore the most consequential aspect of distribution tariff regulation, both for the level of retail tariffs and for the financial health of distribution utilities. Key regulatory issues in power purchase cost determination include: the assessment of whether the distribution utility's power procurement portfolio is optimally structured (in terms of the mix of long-term and short-term contracts, the contract terms and pricing, and the mix of generation technologies); the mechanism for passing through actual power purchase costs to consumers while maintaining incentives for efficient procurement; and the treatment of surplus or deficit power procurement arising from deviations between actual demand and the generation contracted under long-term PPAs.

SERCs face a difficult regulatory challenge in assessing power purchase cost prudency: distribution utilities enter into long-term PPAs of 25 years on the basis of demand forecasts and tariff projections that may prove inaccurate over a horizon of this length, and the Commission cannot reasonably penalise a utility for procuring power under a long-term PPA that seemed prudent at the

time of procurement but subsequently proves to result in excess supply given lower-than-projected demand growth. At the same time, the Commission must guard against imprudent procurement that exposes consumers to unnecessarily high electricity costs — for instance, procurement of excess long-term capacity at above-competitive tariffs, or failure to take advantage of competitive procurement mechanisms when lower-cost options were available.

3.3 Distribution Loss Regulation: Determination, Targets, and Incentives

The regulatory treatment of distribution losses — the electricity that enters the distribution network but is not billed to and recovered from consumers — has evolved significantly since the early days of SERC regulation in India. The evolution reflects the growing recognition that distribution loss reduction is the single most important determinant of distribution utility financial health and that regulatory design must create effective incentives for utilities to invest in loss reduction rather than simply recovering the cost of losses in the tariff.

The approved AT&C loss level in a distribution utility's MYT order specifies the distribution loss percentage that the utility is allowed to recover in its ARR computation. If the utility achieves a lower actual loss level, the resulting additional revenue (from selling more electricity from a given procurement) is shared between the utility (as an incentive payment) and consumers (through lower tariffs in the subsequent regulatory period). If the utility's actual losses exceed the approved level, the financial impact is borne by the utility: its actual revenues fall short of what was projected in the ARR computation, and the shortfall is not automatically recoverable through higher tariffs unless it arises from factors entirely outside the utility's control (such as abnormally high electricity theft in areas affected by civil unrest).

3.4 Consumer Category Design and Tariff Schedules

The design of retail electricity tariff schedules — specifying the tariff applicable to each consumer category, the structure of charges (fixed, energy, demand), and the slab boundaries for multi-slab tariffs — is one of the most complex and politically sensitive aspects of the SERC's tariff regulatory function. The tariff schedule must: generate total revenues equal to the approved ARR; reflect the cost of supply for different consumer categories to the extent consistent with the cross-subsidy provisions of the Tariff Policy; comply with the constitutional requirement of equal treatment under Article 14 (requiring rational differentiation among consumer categories); and be understandable and predictable for consumers.

The number of consumer categories maintained by Indian SERCs has grown over time as utilities and regulators have attempted to capture the diversity of electricity consumption patterns and service requirements in the tariff structure. A typical state SERC tariff order may specify separate tariffs for: domestic consumers at three or four consumption slabs; commercial consumers at one or two tariff levels; low-tension (LT) industrial consumers by connected load bracket; high-tension (HT) industrial consumers by supply voltage level and connected demand; agricultural consumers by pump horsepower; public street lighting; public water supply and sanitation; religious and charitable institutions; electric vehicle charging stations; railway traction; and several other specialised consumer categories. The proliferation of categories reflects genuine differences in the cost of supply, consumption patterns, and social policy priorities but also creates administrative complexity and classification disputes.

3.5 Cross-Subsidy Computation and Rationalisation

The determination of the cross-subsidy embedded in each consumer category's tariff requires a comparison of the category-specific tariff with the category-specific cost of supply (COCS). The COCS for a consumer category is the fully allocated cost of providing electricity to that category, including the allocated share of generation cost, transmission cost, distribution cost, and system balancing cost. The allocation of these costs among consumer categories requires judgements about the appropriate cost driver for each cost component: generation costs may be allocated on the basis of peak demand (since generation capacity must be sized to meet peak demand); transmission costs on the basis of contracted transmission capacity; and distribution costs on the basis of energy throughput or connected load.

Cross-subsidy = Category Tariff − COCS. A positive cross-subsidy indicates that the category pays more than its full cost of supply and is therefore cross-subsidising other categories; a negative cross-subsidy (or "subsidy") indicates that the category pays less than its full cost and is receiving a subsidy funded by the cross-subsidies from other categories. The Tariff Policy requires that cross-subsidies (both positive and negative) be progressively reduced towards zero, with the category-specific tariff converging towards the COCS within the specified rationalisation trajectory. In practice, this trajectory has rarely been fully implemented by SERCs, as the political pressures against agricultural and domestic tariff increases have consistently outweighed the regulatory mandate for cross-subsidy rationalisation.

3.6 True-Up Mechanism: Annual Reconciliation

The annual true-up mechanism — under which the Commission reconciles the approved MYT parameters for the preceding year with the utility's actual costs and revenues and adjusts the regulatory balance accordingly — is the primary instrument for ensuring that the MYT framework does not result in systematic over-recovery or under-recovery by the distribution utility. The true-up proceeding involves: the utility filing an annual performance review petition setting out its actual costs and revenues for the preceding year; the Commission scrutinising the actual figures against the MYT-approved benchmarks; the computation of the true-up adjustment (the difference between the approved ARR and the actual adjusted ARR); and the determination of the mechanism for recovering or passing back the true-up amount in the subsequent tariff period.

3.7 Tariff Orders: Structure, Reasoning, and Transparency

A well-designed SERC tariff order is a detailed analytical and quasi-judicial document that addresses all material issues raised in the tariff proceeding, provides reasoned findings on each component of the ARR, explains the basis for any departures from the utility's proposals or from previous regulatory precedents, and sets out the approved tariff schedule in clear and unambiguous terms. The quality of tariff orders varies considerably across SERCs: the more experienced and better-resourced Commissions (such as MERC, GERC, and DERC) issue comprehensive and analytically rigorous orders that set high standards for transparency and regulatory accountability; less well-resourced Commissions sometimes issue orders that are less comprehensive in their analytical coverage and less transparent in their reasoning.

The transparency and quality of tariff orders is important not only for the immediate parties (the utility and its consumer stakeholders) but for the broader investment community. Investors in electricity sector infrastructure — including private generators with long-term PPAs with the distribution utility and commercial banks lending to distribution capital expenditure programmes — assess the quality and predictability of the SERC's regulatory framework as part of their investment risk assessment. SERCs that issue high-quality, predictable, and legally sound tariff orders are better able to attract private investment

into their state's electricity sector, reducing the financing costs of infrastructure development and ultimately benefiting consumers through lower tariffs and better service quality.

3.8 Electricity Tariff and GST: Regulatory Interface

The Goods and Services Tax (GST) implications for electricity tariff regulation have been discussed briefly in the supplementary analysis section of Booklet I. This section examines the specific regulatory treatment of GST costs in distribution tariff determination by SERCs, an issue that has been a source of significant regulatory controversy since the introduction of GST in July 2017.

The principal issue is that distribution utilities pay GST on a wide range of inputs used in their operations — including power infrastructure equipment (transformers, cables, meters), construction services for network expansion, IT systems and software, and professional services — but cannot claim input tax credit (ITC) on these GST payments because the output (electricity supply) is exempt from GST. This "inverted duty structure" means that the entire GST paid on inputs becomes an irrecoverable cost for distribution utilities, forming part of their cost base that must be recovered from consumers through the regulated tariff.

SERCs have addressed the GST cost issue in their tariff orders, generally recognising the stranded GST cost as a legitimate element of the regulated utility's cost base. However, the treatment varies across states: some SERCs have allowed the actual GST cost paid on capitalised items to be included in the approved capital cost (increasing the depreciation, interest, and return on equity components of the AFC); others have treated the GST as a current year operating expense; and others have required the utility to demonstrate that the specific GST payments were genuinely non-creditable before allowing their inclusion in the tariff. The absence of a uniform national guidance on the GST treatment in electricity tariff regulation has led to inconsistent approaches across SERCs and to regulatory disputes when utilities argue that SERCs have improperly disallowed legitimate GST costs.

3.9 Regulatory Asset and Liability Balances

Regulatory assets and regulatory liabilities are accounting constructs used in electricity tariff regulation to capture the accumulated differences between the approved ARR and the actual revenues and costs of the distribution utility, which are carried forward to be recovered or passed back in future tariff periods. A regulatory asset represents a deferred revenue entitlement: the utility is entitled to recover this amount from consumers in future tariff periods, representing a past under-recovery of its approved ARR. A regulatory liability represents a deferred obligation to pass back to consumers: the utility has collected revenues in excess of its approved ARR and must return the excess through lower future tariffs.

The management of regulatory assets and liabilities is a significant financial planning and regulatory challenge for distribution utilities. Large regulatory asset balances can become a financial burden if they are not recovered in a timely manner: the carrying cost of large regulatory assets (the interest cost of the capital tied up in unrecovered regulatory balances) can be substantial, and prolonged non-recovery can impair the utility's financial health even if the Commission has formally recognised the regulatory asset. CERC and the SERCs have addressed regulatory asset recovery in their MYT frameworks by specifying the rate of return allowed on outstanding regulatory asset balances and the trajectory for their amortisation over the regulatory period.

3.10 Performance-Based Incentives and Penalties in Distribution Tariffs

Performance-based regulatory mechanisms — which link the distribution utility's financial outcomes to its performance against specified benchmarks — are an important complement to the basic cost-of-service framework for ensuring that regulated utilities maintain and improve their operational performance. The primary performance-based mechanisms used in Indian distribution tariff regulation include: the AT&C loss incentive/disincentive scheme; the reliability performance incentive scheme (based on SAIFI and SAIDI targets); the customer service performance scheme (based on the utility's performance against the SERC's standards of performance targets); and the capital expenditure efficiency scheme (rewarding utilities for delivering capital projects below approved cost estimates and on schedule).

The design of performance-based incentive schemes requires careful attention to the risk allocation between the regulated utility and its consumers. An incentive scheme that places too much risk on the utility (for instance, by penalising the utility heavily for performance shortfalls that arise from factors partially beyond its control, such as extreme weather events or vandalism) may discourage prudent risk management and investment decisions. An incentive scheme that places too little risk on the utility (by allowing full cost pass-through for all performance shortfalls regardless of their cause) provides weak efficiency incentives and may encourage the utility to underinvest in performance improvement. Well-designed performance incentive schemes identify the factors within the utility's control (where the utility should bear the risk of shortfall) and distinguish them from factors outside its control (where the risk should be shared with or borne by consumers).

CHAPTER FOUR

Tariff Regulation for Renewable Energy

Competitive Bidding, Benchmark Costs, Must-Run Status, and Curtailment Compensation

The dramatic cost reduction in solar and wind energy over the past decade has fundamentally transformed the regulatory framework for renewable energy procurement in India. This chapter examines the legal and regulatory mechanisms through which renewable energy is procured and tariffed.

4.1 The Evolution of RE Tariff Policy

India's renewable energy sector has undergone a remarkable transformation in the two decades since the passage of the Electricity Act, 2003. In 2003, renewable energy (excluding large hydro) contributed less than 5 per cent of India's electricity generation and was largely confined to wind energy projects in Tamil Nadu and Karnataka. The Electricity Act's provisions on renewable purchase obligations and the broader policy framework of the National Action Plan on Climate Change (2008) and the National Solar Mission (2010) provided the statutory and policy foundations for the rapid expansion of renewable energy that followed.

The most dramatic developments have occurred in solar energy, where the tariff for utility-scale solar photovoltaic projects fell from Rs. 10.95 per kWh in the first batch of the JNNSM in 2010 to below Rs. 2.50 per kWh in recent tenders — a reduction of more than 75 per cent in real terms over 13 years. This cost reduction reflects: the extraordinary decline in solar module prices driven by Chinese manufacturing economies of scale; improvements in inverter technology, balance-of-system components, and project design that have reduced non-module costs; improvements in project finance terms as lenders and equity investors have become more comfortable with solar technology risk; and the intensification of competition among developers in competitive tender processes. Similar cost reductions have been achieved in wind energy, though the extent of reduction is smaller given the less dramatic reduction in wind turbine costs compared to solar module costs.

4.2 Central Government Scheme Architecture for RE Procurement

The institutional architecture for large-scale renewable energy procurement in India involves a complex interaction between multiple central and state government agencies. At the central level, the Solar Energy Corporation of India (SECI) and the National Thermal Power Corporation (NTPC) serve as central procurement agencies that conduct competitive tenders for solar, wind, hybrid, and storage projects on behalf of distribution utilities across the country. SECI's role has been particularly significant in driving scale in solar procurement: by aggregating demand from multiple distribution utilities across states into large single tenders, SECI has enabled the economies of scale necessary to attract the world's most competitive bids and has facilitated the sharing of renewable energy resources across state boundaries.

The SECI model typically involves: SECI conducting a competitive tender for a specified capacity of renewable energy under a tariff-based competitive bidding process; the successful developer entering into a PPA with SECI at the competitively discovered tariff; SECI then entering into back-to-back power sale agreements (PSAs) with distribution utilities in various states at SECI's buying tariff plus a modest trading margin; the PSA tariff being adopted by CERC under Section 63 as part of SECI's inter-state trading; and the state's SERC separately approving the distribution utility's procurement of renewable power from SECI as

prudent and consistent with the state's RPO obligations. This multi-layer structure requires coordination between CERC (which adopts the SECI PPA tariffs), the SERCs (which approve the PSA arrangements for their states' distribution utilities), and the Ministry of New and Renewable Energy (which issues SECI's operational mandate and sets procurement targets).

4.3 Standard Bidding Documents and PPA Terms

The standard Request for Selection (RfS) document and the model Power Purchase Agreement (PPA) for renewable energy projects procured through competitive bidding are important regulatory instruments that standardise the terms of renewable energy procurement, reduce transaction costs, and facilitate the adoption of tariffs by regulatory commissions under Section 63. The Central Government and SECI issue standardised RfS and model PPA documents covering different renewable energy technology categories (solar PV, wind, hybrid, RTC, storage), and these standard documents are updated periodically to reflect changes in technology, market conditions, and regulatory experience.

Key provisions of the model PPA for renewable energy projects include: the contracted capacity and the annual energy commitment or the capacity utilisation factor (CUF) that the developer must achieve; the tariff structure (a single part levelised tariff paid per unit of energy delivered, or in some recent formats, a two-part tariff with a fixed capacity charge and a variable energy charge); the payment security mechanism requiring the distribution utility procurer to maintain a letter of credit covering a specified number of months of PPA payments; the force majeure provisions specifying the events that excuse performance and the consequences of prolonged force majeure; the change-in-law provisions specifying how regulatory or legal changes affecting project costs are allocated between the developer and the procurer; and the curtailment compensation provisions specifying the payment to be made to the developer when generation is curtailed by the system operator for reasons other than grid safety.

4.4 Curtailment and Must-Run: Legal and Commercial Dimensions

The must-run status of renewable energy generators — established by CERC regulation and the Indian Electricity Grid Code — creates legal obligations on the load despatch centres to give priority despatch to renewable energy generation over conventional thermal generation, subject to grid security constraints. This must-run designation reflects both the zero variable cost of renewable generation (ensuring that available renewable generation is used rather than wasted) and the policy imperative to maximise renewable energy utilisation to achieve India's NDC targets and RPO obligations.

Despite the must-run status, renewable energy generators in India have experienced significant curtailment in states with high renewable penetration where the grid infrastructure (particularly intra-state transmission capacity) has not kept pace with renewable capacity addition. In Rajasthan, Tamil Nadu, Andhra Pradesh, and Gujarat, curtailment of renewable generation has at times been significant, creating financial losses for renewable generators whose PPAs typically provide payment only for energy actually delivered to the grid. The regulatory response to this curtailment problem has involved: investment in transmission infrastructure to expand the capacity to evacuate renewable energy from resource-rich areas; changes to the grid code to improve the scheduling and despatch of renewable energy in the energy markets; and the development of curtailment compensation mechanisms that provide some financial protection to renewable generators facing curtailment for non-technical reasons.

CERC has addressed the curtailment compensation issue in several orders, establishing the principle that renewable generators must-run generators that are curtailed for reasons other than grid safety (for instance, because the system operator is deliberately

backing down renewable generation to manage transmission constraints or oversupply in the system) are entitled to compensation from the procurer or from a designated compensation mechanism for the revenue lost due to curtailment. The curtailment compensation framework is still evolving, with debates about the quantum of compensation, the trigger conditions for compensation, and the allocation of the cost of compensation between the distribution utility procurer and the state transmission utility or system operator responsible for managing the transmission constraint.

4.5 Renewable Purchase Obligation: Legal Framework and Enforcement

The Renewable Purchase Obligation (RPO) framework, established under Section 86(1)(e) of the Electricity Act, 2003 and implemented through the RPO specifications of each SERC, is the primary regulatory demand-side instrument for ensuring a minimum level of renewable energy procurement in each state. The RPO creates a legal obligation on specified entities — primarily distribution licensees, but also open access consumers, captive users, and trading licensees in many states' RPO frameworks — to ensure that a minimum percentage of their total electricity consumption comes from renewable sources.

The legal enforceability of the RPO has been a significant concern, as many distribution utilities and obligated entities have consistently fallen short of their RPO targets without facing significant regulatory consequences. CERC and the SERCs have both issued orders highlighting systematic RPO non-compliance and directing obligated entities to develop compliance plans, but the imposition of substantial penalties for RPO non-compliance has been constrained by: the financial stress of distribution utilities (which would pass any penalty cost through to consumers); the limited availability of affordable renewable energy in some states; and the political sensitivity of actions against state distribution utilities by their state's SERC.

4.6 Renewable Energy Certificates: Market Operations

The REC mechanism has operated since 2011 through the Power Exchanges (IEX and PXIL), with RECs being traded in periodic sessions held on the Power Exchanges. The market has experienced periods of illiquidity and price volatility reflecting: the mismatch between the supply of RECs (driven by the accreditation and issuance pace of eligible renewable generators) and the demand for RECs (driven by the RPO compliance behaviour of obligated entities); the uncertainty about RPO enforcement and the consequent weakness of demand from non-compliant obligated entities; and the changes in REC price floors and ceilings introduced by CERC to stabilise the market. The introduction of Green Day-Ahead Market (G-DAM) contracts on the power exchanges, which bundle renewable energy commodity with renewable energy attribute, has provided an alternative avenue for renewable energy attribute trading that competes with the REC mechanism.

4.7 Offshore Wind Tariff and Procurement Framework

India's first offshore wind competitive tender for 1 GW of capacity off the Gujarat coast was issued in late 2023, marking the beginning of India's offshore wind procurement programme. The tariff framework for offshore wind reflects the higher capital cost of offshore projects compared to onshore wind: the benchmark capital costs for offshore wind in India are estimated at Rs. 18–22 crore per MW, compared to approximately Rs. 5 crore per MW for onshore wind, reflecting the cost of offshore foundations, installation vessels, inter-array cables, and offshore export cable systems. The financial viability of offshore wind in India depends on the combination of the competitively discovered tariff, the long-term PPA duration, and the waiver of ISTS

transmission charges for offshore wind generation (which applies for a specified period under the relevant Ministry of Power order).

The regulatory framework for offshore wind involves several novel issues beyond those applicable to onshore wind: the permitting process for offshore wind zones requires coordination with multiple central government ministries including Earth Sciences, Shipping, and Defence; the offshore transmission infrastructure (cable from offshore platform to onshore substation) requires a regulatory framework specifying whether it is part of the wind farm's regulated asset base or a separately licensed and regulated transmission infrastructure; and the environmental clearance process for offshore wind farms must address the impacts of offshore construction on marine ecosystems, fisheries, and navigation.

4.8 Green Hydrogen and Renewable Electricity: Tariff Interface

The development of green hydrogen production as a significant use of renewable electricity in India requires a regulatory framework that efficiently integrates the hydrogen sector's electricity procurement into the existing tariff and open access framework. The key regulatory accommodations required for green hydrogen competitiveness include: waiver or reduction of ISTS transmission charges for renewable electricity used in electrolysis; eligibility of electrolysers for the green energy open access framework with a lower capacity threshold; banking provisions allowing hydrogen producers to carry forward surplus renewable generation credits across billing periods; and treatment of the RPO implications of electricity consumed in electrolysis.

MNRE's guidelines on green hydrogen electricity procurement address these issues by specifying that: green hydrogen producers who develop dedicated renewable energy capacity under the open access framework are exempt from ISTS charges for a specified period; green hydrogen producers who procure renewable electricity through the green energy open access framework at the 100 kW threshold qualify for the same ISTS charge exemption; and energy banking is available to green hydrogen producers on terms comparable to those applicable to other renewable energy open access users. The implementation of these guidelines through CERC and SERC regulations is ongoing, with some states having issued specific orders implementing the green hydrogen electricity procurement framework and others still developing their regulatory positions.

4.9 Hybrid Project Tariff Design

Hybrid renewable energy projects — combining wind and solar generation at the same grid connection point, sometimes with battery storage — present specific tariff design challenges that go beyond the straightforward per-unit competitive tariff applicable to pure solar or wind projects. The key design issues for hybrid project tariffs include: the definition of the contracted quantum of generation (whether expressed as installed capacity, AC capacity at the grid connection, or a guaranteed energy delivery obligation); the payment mechanism (whether a single levelised per-unit tariff for all energy delivered, or a two-part tariff distinguishing between capacity availability and energy delivery); and the performance guarantee framework (including the consequences of underperformance relative to the guaranteed CUF or energy delivery level).

CERC has addressed hybrid project tariff design in its competitive bidding adoptions for wind-solar hybrid projects procured under SECI's hybrid tender programmes. The tariff orders for these projects provide important regulatory precedents for: the treatment of energy from the wind and solar components as interchangeable for payment purposes (the single per-unit tariff applies to total hybrid output regardless of source); the minimum guaranteed capacity utilisation factor that triggers compensation

for CUF shortfall; and the scheduling and despatch provisions applicable to the hybrid project's variable and potentially more predictable combined output. These precedents are being further developed as the first generation of hybrid projects completes its commissioning and begins commercial operation.

4.10 Future of RE Tariff Regulation: Zero or Negative Prices

As India's renewable energy capacity expands towards and beyond the 500 GW target, periods of excess renewable generation will become increasingly common, potentially resulting in very low or even negative wholesale electricity prices during high-renewable periods. This is already occurring in some grid management zones of India during high solar hours in states with large solar capacity, where the system operator must curtail renewable generation to maintain grid balance in the absence of sufficient flexible load or storage to absorb the surplus. The regulatory framework must evolve to address this reality, including through the development of dynamic tariff mechanisms, storage procurement frameworks, and demand response programmes that can absorb surplus renewable generation efficiently.

The emergence of zero or negative electricity prices in real-time markets during periods of excess renewable generation has important implications for the regulatory framework for PPAs signed under the current tariff regime. Most existing renewable energy PPAs specify a fixed per-unit tariff payable for all energy delivered, without any provision for the event that the market price of electricity falls to zero or below. If the procurer (distribution utility) is contractually obligated to pay the agreed tariff for must-run renewable energy regardless of the wholesale market price, the financial cost of the PPA obligation in periods of excess supply could become significant. The regulatory and contractual treatment of this emerging issue — including the question of whether procurers can seek renegotiation of must-run obligations under existing PPAs in periods of persistent excess renewable supply — is a significant area of emerging regulatory risk that the CERC, SERCs, and APTEL will need to address.

CHAPTER FIVE

Network Pricing: Transmission and Distribution Tariff Design

ISTS Methodology, Wheeling Charges, Open Access Costs, and Efficient Network Economics

Network pricing sits at the heart of competitive electricity market development. How transmission and distribution charges are designed determines whether open access is economically viable, whether renewable energy can reach distant consumers, and whether competitive markets can deliver efficiency gains.

5.1 Transmission Network Economics

Electricity transmission networks exhibit several distinct economic characteristics that have important implications for the design of transmission tariffs and the regulation of transmission access. First, transmission networks are capital-intensive assets with very long economic lives: the towers, conductors, and substations that constitute a transmission network have useful lives of 30–40 years, and the capital invested in these assets must be recovered over this extended period through regulated tariffs. The capital intensity of transmission investment means that the annual fixed cost of the transmission network (depreciation plus return on capital) is large relative to the variable cost of network operation, and cost recovery through tariffs must be structured to accommodate this fixed-cost-heavy cost structure.

Second, transmission networks are characterised by significant externalities and public good characteristics: the transmission capacity between any two points in the network is jointly produced by all the elements in the network between those points, and the use of the network by one party affects the availability and cost of network services to all other parties. This interconnected character makes it technically difficult to allocate the cost of the transmission network to individual users on the basis of their specific use of network elements, and creates scope for disputes about cost allocation methodologies.

Third, transmission networks are subject to physical constraints (thermal limits, voltage limits, and stability limits) that affect the ability of network users to inject and withdraw power at different points in the network. These constraints create locational differences in the value of electricity — the "locational marginal price" or "nodal price" — that reflect the cost of transmission congestion. Efficient transmission pricing should, in principle, reflect these locational differences, providing signals for the efficient location of generation and load and for investment in transmission expansion to relieve costly congestion. However, the implementation of locational pricing requires sophisticated market infrastructure and creates significant redistribution of costs among network users.

5.2 ISTS Charge Computation: Annual Transmission Cost

The total ISTS annual transmission cost (ATC) is the sum of the annual transmission charges for all individual ISTS elements (transmission lines, substations, and associated assets) determined through CERC's project-specific tariff orders. PGCIL (as the CTU and the owner of the vast majority of ISTS assets) and private transmission licensees who have developed specific ISTS elements under the competitive transmission development framework both receive tariff payments from the shared ISTS charge

pool, distributed according to their share of the total ISTS asset base.

The computation of the annual transmission charge for an individual ISTS element follows the same cost-based methodology as central generating station tariff determination. The AFC comprises: depreciation on the approved capital cost at the rates specified in the CERC Tariff Regulations; return on equity at 15.5 per cent per annum on the normalised 30 per cent equity component; interest on long-term loans on the normalised 70 per cent debt component at the approved weighted average interest rate; interest on working capital; and O&M expenses at the normative levels specified in the Regulations. The aggregate of these AFC components across all ISTS elements constitutes the total ATC that must be shared among ISTS users through the sharing methodology.

CERC's approach to the computation of the O&M expense norms for ISTS assets reflects the specific cost characteristics of transmission infrastructure. The O&M expense for transmission lines is normalised on a per-circuit-kilometre basis, with separate norms for different voltage levels (765 kV, 400 kV, 220 kV, and 132 kV) and different terrain categories (plains, hilly). The O&M expense for substations is normalised on a per-bay basis, with separate norms for different transformer sizes and voltage levels. These normative O&M parameters are set based on CERC's analysis of PGCIL's actual O&M costs and benchmarks from comparable transmission utilities in other countries, and are reviewed and updated at each regulatory period.

5.3 ISTS Sharing Methodology: Beneficiary States and Point of Connection

The allocation of the total ISTS annual transmission cost among users is the most complex and contested element of the ISTS regulatory framework. The fundamental challenge is that the ISTS is a shared networked infrastructure from which all generators and distribution utilities connected to the grid benefit, but the extent and nature of the benefit derived by different users varies significantly depending on the power flows on the network and the location of each user relative to other users. Any allocation of the total ISTS cost among users will be imperfect in some respect — it will either over-charge some users relative to their specific use of the network or under-charge others — and the choice of methodology therefore involves distributional trade-offs that affect the commercial interests of different participants.

The current CERC (Sharing of ISTS Charges and Losses) Regulations, 2020 establish a hybrid methodology that applies different allocation approaches to different categories of users, reflecting the specific policy objectives applicable to each category. Renewable energy generators connected to the ISTS are allocated zero ISTS charges during the waiver period specified in the Regulations (initially 25 years for solar and wind projects commissioned before the end of the ISTS waiver period), reflecting the policy objective of reducing the delivered cost of renewable electricity to distribution utility procurers and thereby accelerating renewable energy deployment. Conventional generators (thermal, hydro, and nuclear) are allocated transmission charges using the "MW-mile" method, which computes each generator's contribution to the ISTS transmission charge as the product of its scheduled injection capacity and the total of the circuit-lengths (in km) of the ISTS elements used in transmitting its power to load centres, with appropriate sharing of transmission costs along common transmission corridors.

5.4 Green Energy Corridor and New Transmission Infrastructure

The Green Energy Corridor (GEC) programme, launched by the Central Government in 2013 and expanded subsequently, represents one of the largest investments in electricity transmission infrastructure in India's history, specifically designed to

facilitate the evacuation and integration of large-scale renewable energy. The GEC involves the construction of dedicated high-voltage transmission lines from renewable energy-rich states (particularly Rajasthan, Gujarat, Andhra Pradesh, Karnataka, Tamil Nadu, Himachal Pradesh, and Jammu & Kashmir) to load centres in other states, complemented by inter-state transmission capacity enhancements needed to carry the growing share of renewable energy from resource-rich to resource-poor states.

The regulatory treatment of GEC transmission assets for tariff purposes follows the standard ISTS methodology: PGCIL or private transmission licensees who develop GEC assets receive regulated tariffs determined by CERC on a cost-of-service basis, and the GEC assets' tariffs are included in the total ISTS ATC shared among ISTS users. The specific issue of whether the GEC transmission costs should be shared among all ISTS users (including states that do not directly procure renewable energy through the GEC) or only among states that benefit from GEC connectivity has been a subject of inter-state regulatory controversy. CERC's position, supported by the general principle of a shared, integrated national grid, is that the GEC transmission costs form part of the common ISTS cost pool shared among all users, given that the GEC assets contribute to the overall resilience and flexibility of the national transmission network from which all users benefit.

5.5 Distribution Wheeling Charges: Methodology and Controversy

The distribution wheeling charge — payable by open access users for the use of the distribution licensee's network to carry electricity from the network injection point to their premises — is determined by the relevant SERC based on the cost of the distribution network assets used in providing wheeling service. The wheeling charge methodology involves: identifying the distribution assets (conductors, transformers, substations, and associated equipment) that constitute the distribution network; computing the annual cost of these assets (comprising depreciation, return on equity, interest on debt, and O&M expenses) using the same cost-of-service principles applicable to the distribution ARR; and allocating this annual network cost among the users of the distribution network — captive consumers receiving supply from the distribution licensee and open access users — in proportion to their respective contributions to the utilisation of the network.

The controversy surrounding distribution wheeling charges arises from several sources. First, there is no universally agreed methodology for allocating distribution network costs among different categories of users, and the choice of methodology has significant implications for the quantum of the wheeling charge and therefore the economics of open access. A capacity-based allocation (allocating costs in proportion to peak demand) tends to produce higher wheeling charges for large industrial consumers with high peak demands, while an energy-based allocation (in proportion to energy throughput) tends to produce more moderate charges. Second, the treatment of the distribution licensee's own supply operations as a "user" of the distribution network — and specifically, how much of the distribution network cost should be attributed to the licensee's own supply function versus to the wheeling service — affects both the wheeling charge and the regulated supply tariff and can create cross-subsidisation between the two functions.

5.6 Cross-Subsidy Surcharge: Legal Basis and Determination

The cross-subsidy surcharge (CSS), payable by open access users in addition to the wheeling charge under Section 42(4) of the Electricity Act, 2003, is the regulatory instrument designed to prevent the financial deterioration of the distribution utility that would result if its highest-paying customers (large industrial and commercial consumers) migrated to open access, leaving the utility's fixed costs to be borne by a smaller and generally lower-paying consumer base. The CSS is intended to capture the cross-

subsidy that the departing open access user was providing to other consumer categories through their above-cost tariff, ensuring that their exit does not increase the tariff burden on the remaining consumers.

The determination of the CSS involves a calculation of the cross-subsidy that the departing consumer category provides to other categories in the distribution utility's regulated tariff structure. Specifically, the CSS is computed as: (Category Tariff − Category Cost of Supply) × Category Units Consumed, divided by total open access units from the category. A consumer category whose tariff exceeds the cost of supply provides a positive cross-subsidy; the CSS charged to open access users from this category is designed to recover this cross-subsidy from the open access user (who would otherwise escape this contribution by procuring through open access at the wheeling charge rather than through the regulated tariff).

The CSS framework has been the subject of extensive regulatory and judicial controversy. Open access users argue that the CSS should be reduced or eliminated because: it creates a significant financial disincentive to exercise the open access right granted by the Electricity Act, 2003; the cross-subsidy calculation often uses tariff-cost comparisons that overstate the actual cross-subsidy by using average cost of supply rather than marginal cost; and the underlying cross-subsidy structure itself should be reformed rather than perpetuated through the CSS mechanism. Distribution utilities and state governments argue that the CSS is essential for protecting the financial viability of distribution utilities and the interests of the subsidised consumer categories, and that premature or excessive open access that undermines the CSS would accelerate the financial deterioration of already financially stressed distribution utilities.

5.7 Additional Surcharge: Policy and Legal Analysis

The additional surcharge (AS), payable by open access users under Section 42(4) of the Act, is designed to recover the fixed cost of the conventional generation capacity contracted by the distribution utility that becomes "stranded" (underutilised) when open access users reduce their consumption from the distribution utility's supply. When a large industrial consumer exits the distribution utility's supply through open access, the distribution utility still owes capacity charges (Annual Fixed Charges) to the conventional generating stations contracted under long-term PPAs, even though the consumer who was contributing to the payment of these charges is no longer purchasing from the utility. The AS is designed to ensure that the departing consumer continues to contribute to the fixed cost of the stranded conventional capacity.

The computation of the AS involves: identifying the contracted conventional generation capacity whose fixed cost is stranded by open access departures from the distribution utility's consumer base; computing the per-unit cost of this stranded capacity (total stranded AFC divided by total units of generation from stranded capacity); and specifying this cost as the AS payable by open access users. The AS framework is legally complex because: the determination of which generation capacity is "stranded" by open access departures is not straightforward, since the distribution utility can also reduce its short-term power purchases in response to reduced load; the AS computation requires detailed data on the distribution utility's power procurement portfolio that may not be readily available to open access applicants; and the AS may effectively negate the economic benefit of open access for large consumers, creating a regulatory barrier to competition.

5.8 Green Energy Open Access Rules, 2022: A New Framework

The Electricity (Promoting Renewable Energy Through Green Energy Open Access) Rules, 2022, notified by the Central

Government under the proviso to Section 176 of the Electricity Act, 2003, represent the most significant reform of the open access framework since the Act's original provisions on non-discriminatory open access were enacted in 2003. The 2022 Rules override any inconsistent provisions of state open access regulations, using the Central Government's power to issue rules under Section 176 to establish a uniform national framework for green energy open access that supersedes the patchwork of state-level regulations that had previously governed the field.

The key reforms introduced by the 2022 Rules include: reduction of the minimum load threshold for open access eligibility from 1 MW (specified in many states' existing regulations) to 100 kW, dramatically expanding the universe of consumers eligible to procure green energy through open access; a mandatory 15-day processing timeline for green energy open access applications, with automatic approval if the application is not explicitly approved or rejected within this period; limitations on the CSS applicable to green energy open access (with specific provisions preventing states from setting CSS at levels that effectively nullify the economic benefit of green open access); provisions for the banking of surplus green energy procured through open access (allowing consumers to carry forward unused green energy credits for use in later billing periods); and provisions for group captive open access at the 100 kW threshold, allowing multiple small consumers to jointly procure green energy through the open access framework.

5.9 Intra-State Transmission: STU Regulation and Coordination

The intra-state transmission network — typically operating at 220 kV, 132 kV, and in some states 110 kV — connects the state's generating stations and ISTS substations to the distribution network. The intra-state transmission is owned and operated by the State Transmission Utility (STU), typically a separate corporate entity created through the restructuring of the State Electricity Board under the Electricity Act, 2003 framework. The STU's tariff is regulated by the SERC, which determines the annual transmission charge for the intra-state transmission assets using cost-of-service principles similar to those applied by CERC for ISTS assets.

The coordination between the ISTS (regulated by CERC) and the intra-state transmission system (regulated by the SERC) is important for ensuring seamless power flows from generators to consumers across the state boundary. The transmission planning process for intra-state expansion must be integrated with CERC's national transmission plan (prepared by the CEA) to ensure that intra-state transmission capacity additions adequately support the expected power flows from the expanded ISTS that the NEP projects. CERC and the SERCs coordinate through the Forum of Regulators on issues of inter-system coordination, including the standards for metering at the ISTS/intra-state boundary (known as the Regional Interface Meters), the settlement of transmission losses at the state-ISTS interface, and the framework for handling congestion on the intra-state system that affects ISTS power flows.

5.10 Future Network Pricing: Locational Marginal Pricing

The introduction of Locational Marginal Pricing (LMP) — a transmission pricing methodology in which the price of electricity at each node in the transmission network reflects the marginal cost of supplying electricity at that specific location, taking into account the physical constraints of the transmission network — is a long-term direction of travel for the evolution of Indian electricity market design. LMP is the standard market pricing mechanism in the most developed wholesale electricity markets globally, including the PJM, MISO, and ISO-NE markets in the United States and the National Electricity Market in Australia.

Under LMP, when the transmission network is unconstrained, electricity prices at all nodes are equal to the system marginal cost of generation. When transmission constraints exist (for instance, when transmission capacity between two regions is insufficient to accommodate all desired power flows at the unconstrained system price), the price at the source of constrained flows is lower than at the sink, with the price difference representing the "congestion component" of the nodal price. This congestion component provides an efficient economic signal: generators at nodes with low prices (due to transmission export constraints) are incentivised to reduce their output or accept lower revenues, while consumers at nodes with high prices (due to transmission import constraints) are incentivised to reduce their consumption or shift to local generation. Investment in transmission capacity between constrained nodes is incentivised by the financial benefit of eliminating the price differential.

CERC has engaged with the concept of LMP in its market design consultations and has received recommendations from technical experts to move towards LMP-based market design. However, the transition from the current scheduling and despatch framework (which does not implement LMP) to a full LMP-based market design is a major institutional undertaking that would require: significant upgrades to the metering, communication, and computing infrastructure of the load despatch centres; development of new market software capable of computing LMP solutions for the full national grid network in near real-time; redesign of the settlement framework for all market participants; and substantial regulatory reform to update the Grid Code, market regulations, and open access framework to accommodate LMP-based pricing. The transition is therefore likely to be gradual, beginning with pilot implementations in specific market segments or geographic zones and progressively expanding as institutional capacity and market readiness develop.

CHAPTER SIX

Tariff Reform Agenda and Consumer Welfare

Cross-Subsidy Rationalisation, DBT, Retail Competition, and the Regulatory Way Forward

The transformation of India's electricity tariff structure from its current cross-subsidy-laden framework to one that is cost-reflective, transparent, and equitable is one of the most important and challenging tasks facing electricity sector policymakers and regulators. This chapter examines the reform agenda and the institutional mechanisms for its implementation.

6.1 The Cross-Subsidy Problem: Scale and Structural Dimensions

The cross-subsidy embedded in Indian electricity tariff structures represents one of the largest sector-specific resource misallocations in the Indian economy. The aggregate financial burden of electricity cross-subsidies — comprising both the implicit cross-subsidies within tariff structures (industrial and commercial consumers paying above cost to support below-cost agricultural and domestic tariffs) and the explicit subsidies paid by state governments under Section 65 arrangements — runs to several lakh crore rupees annually when aggregated across all states. This resource misallocation has multiple adverse consequences: it distorts electricity consumption decisions by all consumer categories (encouraging excess consumption by subsidised categories and suppressing demand by above-cost-paying categories); it impairs the financial health of distribution utilities; it creates regressive distributional effects by providing indiscriminate subsidies to all consumers in a category regardless of income level; and it impedes the development of a competitive electricity market by maintaining large price differentials between the regulated supply tariff and the competitive market price.

The structural dimensions of the cross-subsidy problem make its resolution difficult. The benefit of cross-subsidisation is concentrated and visible to its recipients (agricultural consumers who receive nearly free or heavily subsidised electricity for irrigation, and domestic consumers who pay below-cost rates), while the cost is diffused across many other consumers and taxpayers. The concentrated benefit creates a politically powerful constituency for maintaining cross-subsidies, while the diffuse cost does not create a correspondingly strong constituency for reform. State governments, which face electoral accountability to the beneficiary constituencies, have consistently been reluctant to implement the progressive cross-subsidy rationalisation mandated by the Tariff Policy, using various political and regulatory mechanisms to delay or dilute the implementation of SERC orders that would move tariffs towards cost-reflective levels.

6.2 Direct Benefit Transfer: Design Principles and Challenges

The Direct Benefit Transfer (DBT) mechanism for electricity subsidies, under which the state government pays the electricity subsidy directly to eligible beneficiary consumers' bank accounts rather than through the mechanism of below-cost tariffs, has been proposed in successive iterations of proposed amendments to the Electricity Act, 2003 as the primary instrument for rationalising electricity cross-subsidies without adversely affecting vulnerable consumers. The DBT approach is now established in principle under the existing Section 65 mechanism (under which the state government pays the shortfall between the regulated tariff and the cost of supply directly to the distribution utility rather than through the tariff structure), and the proposed

Electricity Amendment would extend this principle by requiring that all electricity subsidies be paid directly to the beneficiary consumer through Aadhaar-linked bank accounts rather than through the distribution utility.

The transition from cross-subsidy tariffs to DBT requires several institutional preconditions: a comprehensive database of eligible beneficiary consumers linked to their Aadhaar identity and bank accounts; a reliable and timely mechanism for the state government to make monthly DBT payments to millions of beneficiaries; a regulatory framework for setting the "base tariff" at cost-reflective levels from which the DBT subsidy is calculated; and a consumer education programme explaining the new subsidy mechanism to beneficiaries. The administrative challenges of building these institutional preconditions are substantial, particularly in rural areas where many agricultural consumers may not have bank accounts or may have irregular access to the banking system. However, the Pradhan Mantri Jan Dhan Yojana (PMJDY) programme's success in opening bank accounts for a large proportion of previously unbanked rural households has significantly reduced this barrier.

6.3 Retail Competition: Content and Carriage Separation

The introduction of retail competition in electricity supply — under which consumers can choose among multiple competing supply licensees who purchase electricity in the wholesale market and sell to retail consumers over the distribution licensee's network — is the most structurally transformative element of the proposed electricity reform agenda. The "content and carriage" separation model envisaged in the Electricity (Amendment) Bill would separate the "carriage" function (distribution of electricity over the network, which retains its natural monopoly character) from the "content" function (supply of electricity to retail consumers, which becomes a competitive activity). Distribution network companies would regulate access to the network, setting and charging the wheeling charge applicable to all supply licensees, while competing supply licensees would offer retail consumers different tariff products, green energy options, and bundled energy services.

The commercial prerequisites for retail competition include: a well-functioning wholesale electricity market providing supply licensees access to competitively priced electricity at multiple contract horizons (spot, day-ahead, month-ahead, and long-term); an effective balancing and settlement mechanism ensuring that each supply licensee's contracted and actual generation and consumption positions are reconciled on a near real-time basis; a consumer switching framework that enables consumers to change their supply licensee quickly, cheaply, and without discrimination; and a credit management framework ensuring that supply licensees maintain adequate credit support to meet their settlement obligations in the event of financial distress.

The regulatory challenges of implementing retail competition in the Indian electricity sector include: managing the transition from the incumbent distribution licensee's regulated supply activities to competitive supply, including the treatment of the incumbent's existing long-term PPA portfolio; designing the separation of the distribution wires and supply businesses of existing vertically integrated distribution utilities; specifying the regulatory obligations of the separate distribution network company and the supply licensees; and ensuring that the regulatory framework prevents the distribution network company from using its control of the network to discriminate against competing supply licensees to the benefit of its affiliated supply company. These are complex regulatory design questions for which there is significant international experience from jurisdictions that have implemented retail competition (including the UK, Australia, and several US states) that India can draw on.

6.4 Dynamic Pricing and Smart Metering

The deployment of smart meters under the Central Government's Revamped Distribution Sector Scheme (RDSS) is creating the technical infrastructure for more sophisticated retail tariff structures, including time-of-use (TOU) pricing and potentially real-time pricing for large consumers. Smart meters with two-way communication capability enable the distribution utility to: read meter data remotely without physical meter reading visits; implement remote disconnection and reconnection; offer prepaid billing arrangements; and deliver time-varying tariff signals to consumers' in-home energy management systems. These capabilities make it technically feasible to implement TOU pricing for all metered consumers, not just the large industrial and commercial consumers who have historically been the primary users of demand-based tariff structures.

The regulatory framework for smart metering and dynamic pricing is evolving rapidly in India. CERC and the SERCs have issued smart metering regulations specifying the technical standards for smart meters and their communication infrastructure, the data management requirements for smart meter data, and the consumer protection provisions applicable to smart-metered consumers. The Ministry of Power's RDSS guidelines specify the smart meter specifications for the national deployment programme, including the requirement for prepaid billing capability and the standard for the home area network (HAN) interface that allows smart meters to communicate with in-home energy management devices. These regulatory instruments collectively provide the framework within which distribution utilities will deploy smart meters at scale and begin to offer time-varying tariff products to their consumer base.

6.5 Agricultural Electricity and Metering Reform

The reform of agricultural electricity tariffs and the introduction of metering for agricultural consumers is one of the most important and politically sensitive elements of the tariff reform agenda. The current unmetered flat-rate system for agricultural electricity supply — in which farmers pay a fixed monthly charge based on the connected horsepower of their irrigation pump rather than the actual electricity consumed — has several well-documented adverse consequences: it provides no incentive for efficient use of electricity or groundwater; it makes it impossible to accurately measure the electricity consumption of agricultural users and therefore the actual distribution losses of utilities serving rural areas; and it facilitates electricity theft by enabling the misclassification of commercial loads as agricultural connections.

The progressive introduction of agricultural metering under the RDSS programme — which provides financial support for the installation of smart meters for agricultural consumers as part of the programme's distribution infrastructure improvement activities — is creating the conditions for agricultural tariff rationalisation. Once agricultural consumption is accurately metered, SERCs will be able to: determine the actual cost of electricity supply to agricultural consumers (including the full cost of agricultural feeders, distribution transformers, and the metered energy consumption); design tariff structures that provide volumetric incentives for energy and water conservation; and identify the specific subsidy quantum required to maintain agricultural electricity at an affordable level, which can then be transparently provided through Section 65 payments by the state government.

The political challenge of agricultural metering is that farmers have consistently resisted metering on the grounds that it would eventually lead to higher electricity bills for irrigation. State governments in major agricultural states (including Andhra Pradesh, Telangana, Punjab, and Uttar Pradesh) have been reluctant to mandate agricultural metering for fear of adverse electoral consequences. The incentive structure of the RDSS programme — which conditions the release of central financial assistance on the achievement of agricultural metering targets — is designed to provide state governments with the political cover and financial

incentive to implement metering as part of a larger infrastructure improvement programme, rather than as a standalone tariff reform initiative.

6.6 Regulatory Frameworks for Energy Access and Inclusion

The electricity sector's contribution to the achievement of energy access goals for the 300 million-plus people who still lack reliable electricity access in India — despite the near-universal household electrification achieved through the Saubhagya programme — requires a regulatory framework that goes beyond the provision of physical connections to address the quality, reliability, and affordability of electricity supply. The regulatory dimensions of energy access include: the specification of minimum quality-of-supply standards applicable to rural and remote areas that ensure new connections receive electricity at acceptable voltage and frequency levels and for a minimum number of hours per day; the design of low-income lifeline tariffs that provide a minimum quantity of electricity at a socially affordable price; and the regulatory framework for stand-alone and mini-grid solutions for communities that cannot be economically served by the main grid.

Stand-alone solar systems and solar-powered mini-grids are increasingly recognised as the cost-effective solution for electricity access in remote and dispersed settlements where the cost of main grid extension is prohibitive. The regulatory framework for mini-grids under the Electricity Act, 2003 has evolved through the Ministry of New and Renewable Energy's Guidelines for Development of Smart Mini Grids and the respective state governments' mini-grid policies. The regulatory challenge for mini-grids is to: ensure that mini-grid operators can recover their investment through tariffs set at affordable levels for low-income rural consumers (which may require cross-subsidy from the state budget or from carbon credit mechanisms); prevent the financial disruption of mini-grid operators when the main grid eventually extends to their service area (which can render the mini-grid uneconomic if consumers defect to the (typically subsidised) grid supply); and maintain appropriate safety and service quality standards without imposing regulatory burdens that are disproportionate to the small scale of individual mini-grid operations.

6.7 Consumer Rights and Grievance Redressal

The consumer rights provisions of the Electricity Act, 2003 — including the Standards of Performance for distribution licensees specified by SERCs under Section 57, the consumer grievance redressal forums (CGRF) established under Section 42(5), and the Electricity Ombudsman framework — create a multi-tier framework for the protection of electricity consumers' interests. These provisions are an important complement to the economic regulation framework of tariff determination: even if tariffs are set at appropriate cost-reflective levels, consumers are adversely affected if the distribution utility fails to maintain reasonable standards of service quality, fails to respond promptly to consumer complaints, or imposes arbitrary or unreasonable charges and conditions on consumers.

The Standards of Performance specified by SERCs under Section 57 cover a range of service quality dimensions including: connection and reconnection timelines; voltage quality standards; outage frequency and duration; meter accuracy and testing; billing accuracy and dispute resolution; and response times for consumer complaints. Licensees who fail to meet these standards are required to pay compensation to affected consumers, creating a direct financial incentive for service quality improvement. The regulatory enforcement of service quality standards has been strengthened in recent years by the development of automated performance monitoring systems (supported by RDSS scheme investment in distribution management systems) that provide the SERC with accurate and timely data on the distribution utility's actual performance against specified standards.

6.8 Electricity Prosumers and Net Metering

The rapid growth of rooftop solar installations in India — driven by the PM Surya Ghar Muft Bijli Yojana and falling solar panel prices — is creating a new and growing class of electricity prosumers: consumers who both consume electricity from the grid and generate electricity from their rooftop solar installations, selling the surplus to the distribution utility or banking it for later use. The net metering framework, under which a prosumer's electricity bill is computed on the basis of the net difference between their grid consumption and their grid injection (with the surplus credited at the applicable rate), is the primary regulatory mechanism for enabling prosumer participation in the electricity system.

SERCs have issued net metering regulations specifying the eligibility criteria for net metering (typically, residential consumers with rooftop solar installations up to a specified capacity), the applicable credit rate for surplus energy fed into the grid, the billing settlement period (typically monthly or annually), and the technical requirements for the bi-directional meter needed to measure both consumption and generation. The design of the credit rate for surplus generation — specifically, whether the prosumer receives the full retail tariff rate for surplus generation (which may be above the distribution utility's cost of purchasing equivalent energy in the market) or a lower rate reflecting the wholesale market value of the exported energy — has been a contentious issue in several states, with prosumer advocates arguing for full retail rate credits and distribution utilities arguing for market-rate compensation.

6.9 Electricity Regulatory Reform: Institutional Dimensions

The implementation of the tariff reform agenda described in this chapter requires not only changes in the substantive regulatory framework but also institutional reforms that strengthen the capacity, independence, and accountability of the regulatory commissions. The most important institutional reforms needed include: strengthening the financial and administrative independence of the SERCs by ensuring that they have adequate budgetary resources to attract and retain qualified staff, develop regulatory information systems, and conduct regulatory proceedings of appropriate quality; improving the appointment process for SERC Chairpersons and Members to ensure that qualified and independent candidates are selected based on merit rather than political considerations; strengthening the accountability mechanisms for SERCs, including through enhanced requirements for transparent and reasoned tariff orders and the development of regulatory quality assessment frameworks; and improving the coordination between CERC, the SERCs, and the Forum of Regulators to promote regulatory convergence and reduce the transaction costs of operating across multiple state regulatory jurisdictions.

The capacity building programme for Indian electricity regulators has been supported by several international initiatives including technical assistance from the World Bank, the Asian Development Bank, and bilateral development cooperation programmes. These initiatives have provided training for regulatory staff, support for the development of regulatory information systems, and advisory support for specific regulatory challenges including the design of MYT frameworks, the implementation of smart metering, and the development of renewable energy tariff frameworks. However, the sustainability of these capacity improvements beyond the duration of specific donor-funded programmes remains a challenge, and the development of domestic institutional mechanisms for continuous regulatory capacity improvement is an important governance objective for the electricity sector.

6.10 A Vision for Tariff Regulation: 2030 and Beyond

Looking towards 2030 and beyond, the electricity tariff regulatory framework in India will need to accommodate a series of major structural changes in the electricity sector: the achievement of near-100 per cent renewable energy in the generation mix during favourable weather periods, requiring sophisticated market mechanisms for managing surplus and deficit; the widespread deployment of electric vehicles and their integration as flexible loads and potential storage resources; the proliferation of prosumers with rooftop solar and battery storage who are both consumers and producers of electricity; and the development of retail competition enabling consumers to choose among multiple competing electricity supply providers. Each of these changes creates both regulatory challenges and opportunities for improving the efficiency, equity, and sustainability of the electricity tariff framework.

A 2030 vision for electricity tariff regulation in India might include: fully cost-reflective network tariffs that reflect both locational and temporal variation in network costs, supported by smart metering and advanced network management infrastructure; transparent and targeted electricity subsidies delivered through the DBT mechanism to eligible low-income consumers, with the subsidy quantum determined by the state government on the basis of clear social policy criteria rather than embedded in cross-subsidised tariff structures; dynamic retail electricity pricing that reflects the time-varying wholesale market price of electricity, available to all consumers with smart meters and in-home energy management systems; retail competition enabling consumers to choose among multiple supply licensees offering innovative tariff products, green energy options, and bundled energy services; and a robust consumer protection framework ensuring that the transition to more market-oriented tariff structures does not disadvantage vulnerable consumers who may lack the information, resources, or ability to navigate competitive markets effectively. The regulatory framework of the Electricity Act, 2003, implemented by CERC and the SERCs with the guidance of the Tariff Policy and the jurisprudence of APTEL and the Supreme Court, provides the institutional foundation on which this ambitious reform agenda can be pursued.

EXTENDED ANALYSIS I

CERC Tariff History, Change-in-Law, and Regulatory Orders

Evolution of Cost Parameters, Landmark CERC Orders, and Change-in-Law Jurisprudence

A.1 CERC Tariff Regulations: Evolution Across Regulatory Periods

CERC has issued successive sets of Terms and Conditions of Tariff Regulations covering the following regulatory periods: 2001–2004, 2004–2009, 2009–2014, 2014–2019, and 2019–2024. Each set of Regulations has refined and developed the tariff methodology, responding to industry experience, regulatory learning, and changes in the policy framework. Tracing the evolution of key parameters across these regulatory periods reveals the progressive tightening of efficiency benchmarks, the adjustment of return parameters to market conditions, and the development of new regulatory instruments for emerging technologies and market structures.

The 2001–2004 Regulations, issued shortly after CERC's establishment, established the foundational cost-based framework for central generating stations that has remained the basic architecture of CERC's tariff regulation. The normative heat rates in these initial Regulations were set relatively generously, reflecting the limited availability of benchmarking data on Indian generating unit performance and the need to establish credibility for the new regulatory framework by ensuring that existing generating companies could recover their costs. The 2004–2009 Regulations introduced the Availability-Based Tariff (ABT) mechanism as a core feature of the tariff framework, separating the tariff into fixed and variable components and linking the fixed component to declared availability rather than actual generation. The ABT mechanism represented a significant technical and regulatory advance, creating clear incentives for plant availability improvement and establishing the scheduling and despatch framework that underpins India's electricity market to this day.

The 2009–2014 Regulations introduced important refinements to the capital cost framework, tightening the normative capital cost benchmarks for new projects and introducing more rigorous procedures for the scrutiny of actual project costs. This period also saw the extension of the CERC tariff framework to renewable energy generating stations, with the Commission issuing benchmark capital costs and normative parameters for solar PV, wind, small hydro, and biomass projects under the RE-specific Terms and Conditions of Tariff Regulations. The 2014–2019 Regulations introduced a "trajectory" approach to normative O&M expenses, specifying annual escalation in the normative O&M cost to reflect the expected growth in maintenance requirements as the generating station ages and the general cost escalation in the economy. The 2019–2024 Regulations maintained the broad architecture of the previous period while introducing adjustments to the return on equity rate, the debt-equity ratio normalisation, and the treatment of working capital to reflect changed financing market conditions.

A.2 Change-in-Law in Electricity PPAs: Legal Framework

The change-in-law (CiL) provisions of electricity power purchase agreements address the question of how regulatory or legal changes affecting the cost or revenue of the generator or procurer after the PPA is signed should be allocated between the parties. The CiL framework is one of the most commercially significant and legally contested aspects of electricity PPA regulation in

India, affecting the economics of hundreds of GW of electricity generating capacity under long-term PPAs worth tens of lakh crore rupees over their 25-year operating lives.

The fundamental principle of CiL in electricity PPAs is that the risk of changes in law or regulation applicable to the project — including changes in tax rates, environmental standards, safety requirements, and regulatory parameters — should be allocated to the procurer (distribution utility), on the grounds that: the generating company entered into the PPA on the basis of the law and regulatory framework prevailing at the time of bidding; the generating company has no control over subsequent legal and regulatory changes; and the social cost of legal and regulatory change should be borne by the broad consumer base (through adjustments to the regulated tariff) rather than by the generating company's investors, who would otherwise face an asymmetric risk of bearing the full downside of adverse legal changes while being entitled to no special benefit from favourable changes.

CERC and APTEL have developed extensive jurisprudence on CiL in the context of coal-based and gas-based generating stations under long-term PPAs. The major CiL events that have been the subject of regulatory proceedings and APTEL appeals include: the introduction and subsequent increases in coal cess and clean energy cess levied on coal production; the withdrawal of various income tax exemptions and the introduction of Minimum Alternate Tax (MAT) on power sector SPVs; changes in custom duties on imported coal and project equipment; the introduction of GST and its impact on project costs and input tax credit availability; changes in environmental emission norms requiring additional pollution control equipment investment; and the introduction of the Coal Conservation Fund levies. For each of these CiL events, the Commission must determine: whether the event constitutes a "change-in-law" within the definition of the applicable PPA; whether the event has caused a "material adverse effect" on the project economics sufficient to trigger the CiL relief mechanism; and the quantum of the compensation or tariff adjustment payable to the generating company as a result of the CiL event.

A.3 Fuel Supply Agreements and Regulatory Treatment

The legal and regulatory framework for fuel supply for coal-based thermal generating stations involves complex interactions between the generating company, Coal India Limited (CIL) and its subsidiaries, the Ministry of Coal, and the electricity regulatory commissions. The Fuel Supply Agreement (FSA) between a generating station and the relevant coal company specifies the contracted annual quantity (CAQ) of coal supply, the quality specifications (grade, calorific value, moisture content, and ash content), and the commercial terms for supply. Generating companies that fail to receive the CAQ under their FSA are eligible for the "Domestic Coal Shortfall" mechanism under CERC's regulations, which allows them to claim the additional cost of procuring coal from alternative sources (including imported coal or e-auction coal at higher prices) in their tariff through a fuel cost pass-through mechanism.

The regulatory treatment of coal shortfall has been a major area of CERC regulatory activity and APTEL jurisprudence. The generating company claims that any shortfall in domestic coal supply below the CAQ entitles it to recover the additional cost of alternative coal procurement as a CiL event or as a regulatory pass-through. Procurers argue that the generating company should have managed its fuel supply risk more proactively by diversifying its coal supply sources, entering into supplementary fuel supply agreements, or developing on-site coal storage capacity. CERC has generally upheld the generating company's right to recover the additional cost of alternative coal when CIL's shortfall is attributable to production or logistics constraints beyond the generating company's control, while declining to pass through additional costs arising from the generator's own procurement failures or operational deficiencies.

A.4 Tariff for Ultra Mega Power Projects

The Ultra Mega Power Project (UMPP) programme, launched by the Central Government in the mid-2000s, introduced a novel structure for procuring large-scale (4,000 MW) coal-based generating capacity through tariff-based competitive bidding under the Section 63 framework. The UMPP programme was designed to leverage the scale economies of very large generating stations and the competitive pressure of bidding to achieve lower tariffs than had been available under cost-based regulation for comparable capacity. The programme was implemented through a special-purpose vehicle (Pvt. Ltd. company) structure in which the project development activities (site acquisition, environmental clearance, fuel supply arrangement, water supply, and transmission connectivity) were completed by a government-sponsored company before the project was offered for competitive bidding; the winning bidder acquired the SPV (and therefore the project with its development work completed) and took the project to completion and operation.

The UMPP programme produced significant tariff benefits in the early projects: the Mundra UMPP (awarded to the Tata Power-led consortium in 2007) discovered a tariff of approximately Rs. 2.26 per kWh on a levelised basis, which was significantly below the contemporaneous regulated tariff for equivalent coal-based capacity. Similarly, the Sasan UMPP (awarded to Reliance Power in 2007) produced a tariff of approximately Rs. 1.20 per kWh, reflecting the extremely competitive bidding in that round. These low tariffs were achieved partly through aggressive assumptions about future fuel costs and project economics by the bidders, and partly through genuine efficiencies from scale and competitive pressure.

The financial and regulatory consequences of the UMPP programme's early results have been complex. Several UMPP projects, particularly the Mundra UMPP and the Tiroda UMPP, subsequently experienced severe financial stress arising from: higher-than-projected imported coal prices following the Indonesian government's regulation of coal export prices in 2011, which dramatically increased the fuel cost of the Mundra UMPP (which relied on imported Indonesian coal); delays in completion and cost overruns; and difficulties in obtaining domestic coal linkages at the volumes and prices projected at the time of bidding. The legal proceedings arising from these financial difficulties — involving CERC tariff revision petitions, APTEL appeals, and ultimately the landmark Supreme Court decisions in Gujarat Urja Vikas Nigam v. GUVNL and Adani Power Maharashtra v. Maharashtra Electricity Regulatory Commission — established important precedents for the treatment of fuel price changes in competitive tariff PPAs and the interaction between competitive bidding outcomes and the regulatory framework for cost pass-through.

A.5 Regulatory Treatment of Stranded Assets

The problem of stranded assets — generating capacity for which the generating company cannot recover its prudently incurred investment costs because the off-taking distribution utility is unwilling or unable to enter into a PPA, or because the competitive market has produced prices below the cost of the existing capacity — is a significant regulatory challenge in the Indian electricity sector. Several large privately developed thermal power projects became "stranded" in the period 2013–2018 due to: the failure of state distribution utilities to enter into PPAs for capacity that had been developed in anticipation of power purchase agreements that did not materialise; the deterioration of the financial position of distribution utilities that rendered them unable or unwilling to enter into new PPAs; and the oversupply in the electricity generation market that arose as competitive bidding produced tariffs below the cost of operation of some existing regulated-tariff stations.

The regulatory framework for stranded thermal assets has been the subject of several Central Government and CERC initiatives.

The SHAKTI (Scheme for Harnessing and Allocating Koyala Transparently in India) scheme, introduced in 2017, attempted to address the fuel supply aspect of the stranded asset problem by providing domestic coal linkages to stranded capacity that had been developed without assured fuel supply. The Pradhan Mantri Sahaj Bijli Har Ghar Yojana (Saubhagya) electrification programme created additional electricity demand that absorbed some of the excess generating capacity. The National Load Despatch Centre's coordination of short-term electricity trading provided a market for the electricity from stranded projects that did not have PPAs with distribution utilities. And the Electricity (Amendment) Bill's provisions on the competitive procurement of stranded capacity were designed to provide a regulatory mechanism for rationalising the excess capacity through market processes.

A.6 CERC Tariff Orders: Landmark Decisions

A survey of landmark CERC tariff orders illustrates the range and significance of the regulatory issues that CERC has addressed in its tariff determination function. The following decisions represent important milestones in the development of Indian electricity tariff regulation.

The NTPC tariff orders of the early 2000s, in which CERC determined the tariffs for NTPC's large fleet of coal and gas generating stations under the new cost-based framework of the 1998 and 2001 Regulations, were foundational for the entire CERC tariff regulatory framework. These orders established the methodology for capital cost scrutiny, the approach to fuel cost computation, and the interaction between the CERC tariff framework and NTPC's existing contractual arrangements with state distribution utilities. The early NTPC tariff orders were contested vigorously by both NTPC (which argued for more generous capital cost recovery) and the distribution utility procurers (which argued for tighter cost recovery), and the Commission's reasoned resolutions of these disputes established the basic principles of CERC tariff regulation that continue to govern the framework today.

The Sasan UMPP tariff adoption order of 2008 represented the first adoption of a tariff under Section 63 for a large base-load project procured through competitive bidding. This order established important procedural and substantive precedents for Section 63 adoption proceedings, including the scope of the Commission's review of the bidding process, the treatment of bid qualifications and conditions, and the legal effect of the Commission's adoption order on the PPA tariff. The subsequent regulatory proceedings arising from the financial difficulties of the Sasan UMPP — including the petition for additional compensation for imported coal cost escalation — tested the boundaries of the change-in-law framework in the context of competitive bidding PPAs and produced important jurisprudence on the interaction between competitive tariff discovery and regulatory cost pass-through.

CERC's series of orders on the sharing of ISTS charges, from the initial orders under the 2010 Regulations through the comprehensive revision under the 2020 Regulations, represent a sustained regulatory effort to develop a fair and efficient methodology for allocating the growing ISTS annual transmission cost among the rapidly expanding and increasingly diverse population of ISTS users. These orders addressed the treatment of renewable energy generators (whose exemption from ISTS charges was progressively extended), the methodology for conventional generators (from a simple postage stamp approach to the more sophisticated flow-based methods introduced in the 2020 Regulations), and the treatment of cross-border transactions with neighbouring countries (which raised novel questions about the allocation of ISTS costs to transactions that transit the Indian grid without serving Indian consumers).

A.7 Tariff Regulation and Project Finance: Interaction

The interaction between electricity tariff regulation and project finance — the specialised form of debt financing used for capital-intensive infrastructure projects — is a critical dimension of the electricity sector regulatory framework that significantly affects the availability and cost of finance for electricity infrastructure investment. Project lenders assess the regulatory framework as a key element of the credit risk analysis for electricity infrastructure projects: a regulatory framework that provides credible and durable revenue certainty for the project (through stable tariffs, enforceable off-take commitments, and adequate payment security mechanisms) reduces the project's credit risk and supports lower lending margins and higher debt leverage ratios.

The principal mechanisms through which the CERC tariff regulatory framework supports project finance for central generating stations include: the tariff order itself, which establishes the legal basis for the generator's revenue entitlement for the full term of the PPA; the model PPA, which specifies the off-take commitment of the distribution utility and the payment security requirements (including the mandatory letter of credit and the tripartite agreement mechanism); the change-in-law provisions, which protect the project's revenue stream against adverse regulatory and policy changes; and the availability-based tariff structure, which provides the generator with a fixed charge revenue (AFC) that is contractually payable regardless of whether the generator is actually despatched, provided it maintains the specified level of plant availability.

Lenders to electricity infrastructure projects place significant value on the clarity and stability of the regulatory framework governing the project's revenue. In CERC-regulated projects, the tariff order providing the AFC and ECR for the project is the primary document on which lenders base their financial model, and any regulatory uncertainty about the continued applicability of the tariff order — for instance, arising from a pending CERC review of the approved capital cost, or a disputed CiL claim that could affect the ECR — can impair the project's bankability. The quality of CERC's regulatory processes — including the clarity of its tariff orders, the predictability of its application of regulatory principles, and the speed of its processing of tariff petitions — therefore has direct implications for the cost and availability of project finance for central generating station investments.

EXTENDED ANALYSIS II

Distribution Tariff Orders: Case Studies and Regulatory Practice

State-Level Regulatory Experience, ARR Computation, and Landmark SERC Orders

B.1 Maharashtra Electricity Regulatory Commission: A Model of Regulatory Excellence

The Maharashtra Electricity Regulatory Commission (MERC) is widely regarded as one of India's most professionally competent and procedurally rigorous state electricity regulatory commissions, and its tariff orders provide useful illustrations of best practice in distribution tariff regulation. MERC regulates distribution utilities including Adani Electricity Mumbai Limited (AEML, formerly BSES Maharashtra and then Reliance Infrastructure), Tata Power Company (TPC Distribution, which serves certain areas of Mumbai), Brihanmumbai Electric Supply and Transport (BEST), Maharashtra State Electricity Distribution Company Limited (MSEDCL, the state-owned distribution utility serving the rest of Maharashtra), and the Government of Maharashtra through its power department for certain other areas.

MERC's MYT orders for MSEDCL — the dominant distribution utility in Maharashtra with over 30 million consumers — provide a detailed illustration of the ARR computation and tariff determination methodology for a large, complex distribution utility. The ARR computation for MSEDCL involves hundreds of line items covering the full cost structure of a utility with over 4 lakh circuit kilometres of distribution network, thousands of substations, and a highly diverse consumer mix ranging from Mumbai's large industrial and commercial establishment to the rural agricultural base of Vidarbha and Marathwada. MERC's multi-year tariff orders specify the approved ARR for each year of the control period, the distribution loss trajectory, the capital expenditure plan, and the retail tariff schedule, with detailed reasoning provided for each component of the regulatory determination.

A distinctive feature of MERC's regulatory practice has been its development of detailed regulatory accounts methodology for MSEDCL, specifying the format and content of the regulatory accounts that MSEDCL must submit in support of its annual performance review petitions and tariff revision petitions. The regulatory accounts methodology ensures that MSEDCL's financial information is presented in a form that is directly comparable with the approved MYT parameters, facilitating the Commission's annual true-up computation and reducing disputes about the basis of the regulatory reconciliation. MERC has also been a leader in consumer engagement in tariff proceedings, developing structured public hearing processes that provide consumers, consumer groups, and other stakeholders with meaningful opportunities to participate in tariff determination.

B.2 Gujarat Electricity Regulatory Commission: Regulatory Innovation

The Gujarat Electricity Regulatory Commission (GERC) has been another model of effective state electricity regulation, with a history of innovative regulatory approaches including early adoption of multi-year tariff framework, development of comprehensive open access regulations, and proactive engagement with renewable energy tariff regulation. Gujarat's electricity sector is characterised by a highly industrialised consumer base (Gujarat has one of the highest concentrations of large industrial electricity consumers in India), a large and growing renewable energy sector (particularly solar), and a distribution utility

(UGVCL, PGVCL, DGVCL, MGVCL) structure that reflects the disaggregation of the original Gujarat Electricity Board into separate corporate entities.

GERC's tariff orders have had to grapple with the particular challenges posed by Gujarat's industrial consumer mix: large industrial consumers who pay above-average tariffs are the primary source of cross-subsidy in Gujarat, and their interest in exercising open access rights to escape the cross-subsidy through competitive procurement has been a persistent source of tension with the distribution utilities and the state government. GERC has developed a sophisticated cross-subsidy surcharge and additional surcharge framework that attempts to balance the legitimate interest of industrial consumers in accessing competitive electricity supply with the distribution utilities' need for stable revenue to cover their fixed costs and the cross-subsidised tariffs of domestic and agricultural consumers.

B.3 Delhi Electricity Regulatory Commission: Urban Privatisation Model

The Delhi Electricity Regulatory Commission (DERC) regulates the two private distribution licensees in Delhi — BSES Rajdhani Power Limited (BRPL) and BSES Yamuna Power Limited (BYPL) (both subsidiaries of Reliance Infrastructure) and Tata Power Delhi Distribution Limited (TPDDL) — as well as the Delhi Transco Limited (the state transmission utility) and the New Delhi Municipal Council's distribution operations in the New Delhi area. Delhi's privatised distribution framework, described in Booklet I's discussion of the state-level reform experience, provides a distinctive context for DERC's regulatory practice.

The regulatory challenge for DERC has been managing the implementation of the privatisation compact — under which the private distribution companies acquired the legacy distribution assets at a negotiated price and committed to achieve specified AT&C loss reduction targets and service quality improvements — while ensuring that the regulatory framework provides appropriate incentives for both efficiency and investment. The initial years of the Delhi privatisation were characterised by regulatory disputes about the treatment of the "regulatory assets" created by the difference between the approved tariff and the distribution companies' actual costs in the early years of operation, when the companies incurred costs above the pre-privatisation cost levels. These regulatory asset disputes went to APTEL on multiple occasions and produced important jurisprudence on the recognition, valuation, and amortisation of regulatory assets in Indian electricity distribution regulation.

B.4 Distribution Tariff and Agricultural Subsidy: A Structural Analysis

The treatment of agricultural electricity subsidies in distribution tariff regulation is one of the most structurally complex and financially significant issues in Indian electricity sector governance. Agricultural electricity subsidies in India take multiple forms: the direct below-cost tariff subsidy (where the regulated agricultural tariff is set below the cost of supply, with the shortfall recovered from industrial and commercial consumer cross-subsidies); the state government Section 65 direct subsidy (where the state government pays the distribution utility the difference between the agricultural tariff and the cost-of-supply tariff); and "free power" schemes (where several state governments have provided completely free electricity to agricultural consumers, with the entire cost covered by the state budget).

The free power scheme operated in Andhra Pradesh, Telangana, and Punjab (among other states) provides a useful illustration of the financial and regulatory implications of deeply subsidised agricultural electricity. Under these schemes, the distribution utility bills agricultural consumers at zero tariff (or a nominal rate) for electricity consumed by irrigation pumps, and the state

government pays the entire electricity cost (or the cost above the nominal rate) directly to the utility under the Section 65 mechanism. The financial impact on the distribution utility depends critically on whether the state government actually makes the Section 65 payments on time and in full: where payments are delayed or incomplete, the distribution utility accumulates receivables from the state government that impair its cash flow and financial health.

The regulatory treatment of delayed or unpaid Section 65 subsidies in the distribution utility's ARR and tariff proceedings has been a recurring issue before SERCs. The basic principle is that the distribution utility's ARR should be computed net of the Section 65 subsidy amount that the state government has committed to pay: the subsidy is a revenue that offsets the cost of supplying electricity at below-cost rates to subsidised consumers. If the state government fails to pay the committed subsidy, the distribution utility faces a revenue shortfall that is not automatically recoverable through higher tariffs from other consumers (since the Commission approved the ARR on the assumption of subsidy payment). SERCs have addressed this issue through regulatory asset recognition for unpaid Section 65 subsidies, allowing the distribution utility to carry forward the unpaid subsidy amount as a regulatory asset recoverable in future tariff periods, while also directing the state government to make good the arrears.

B.5 Tariff Policy Implementation: A Scorecard

An assessment of the implementation of the Tariff Policy's key provisions by the SERCs across India reveals significant variation in compliance and a persistent gap between policy aspiration and regulatory practice. The following scorecard assesses implementation against the Tariff Policy's principal provisions.

Cross-subsidy rationalisation towards the ±20 per cent band: partial compliance in most states, with significant states such as Maharashtra, Gujarat, and Delhi having made progress in reducing the extent of cross-subsidies, while many other states continue to maintain large cross-subsidies that significantly exceed the Tariff Policy's prescribed band. The progress in cross-subsidy rationalisation has been particularly slow for agricultural consumers, where political pressures have prevented the level of tariff increases necessary to bring agricultural tariffs within the required range of the cost of supply.

Multi-year tariff framework adoption: near-universal compliance, with all major SERCs having adopted MYT frameworks covering control periods of three to five years. The quality and rigour of MYT implementation varies considerably: well-established commissions have developed sophisticated MYT frameworks with meaningful incentive mechanisms and comprehensive annual true-up processes, while others have adopted the MYT framework more nominally with limited practical impact on regulatory certainty or incentive design.

Competitive procurement under Section 63: high compliance for all new long-term procurement, with the competitive bidding framework now the standard mechanism for procurement of renewable energy and most new conventional capacity. The adoption of competitive bidding tariffs by the Commission has generally been efficient, with CERC adopting tariffs for SECI and NTPC tenders within a reasonable period of the PPA execution.

Universal metering: partial compliance, with significant progress in urban and peri-urban areas but continuing gaps in agricultural and rural domestic metering in many states. The RDSS scheme's targets for smart meter deployment are expected to significantly improve the national metering situation over the 2023–2027 period.

Standards of performance specification: near-universal compliance in form, with all SERCs having specified standards of performance for distribution licensees, though the enforcement of these standards and the payment of compensation to affected consumers varies considerably in practice.

B.6 AT&C Loss Regulation: Methodology and Results

The regulation of Aggregate Technical and Commercial (AT&C) losses — the total electricity lost in the distribution network through both technical causes (resistance losses in conductors and transformers) and commercial causes (meter tampering, unmetered supply, billing errors, and collection failures) — is one of the most important performance dimensions regulated by the SERCs. AT&C losses in India have historically been among the highest in the world, reflecting the legacy of underinvestment in distribution infrastructure, widespread meter tampering and energy theft, and the prevalence of unmetered or flat-rate supply arrangements for agricultural consumers.

The progress in AT&C loss reduction since the enactment of the Electricity Act, 2003 has been significant but uneven. The national average AT&C loss for distribution utilities has declined from approximately 35–40 per cent in the early 2000s to approximately 18–20 per cent in recent years, a substantial reduction but still far above the 10–12 per cent levels achieved by best-practice distribution utilities globally. The distribution of AT&C losses across states is highly uneven: well-managed private distribution utilities in Delhi (TPDDL), Mumbai (AEML), and Surat (DGVCL) have achieved AT&C losses below 8 per cent, while several state distribution utilities in Uttar Pradesh, Bihar, Rajasthan, and Jharkhand continue to report AT&C losses above 30 per cent.

The SERC's role in AT&C loss regulation involves: specifying the approved AT&C loss level for the distribution utility in each year of the MYT control period, based on the utility's historical loss performance, the benchmarked achievable loss level for comparable utilities, and the utility's capital expenditure plan for network improvement and metering upgradation; computing the financial implications of the distribution utility's actual AT&C loss versus the approved level; and designing the incentive/disincentive mechanism that rewards utilities for achieving losses below the approved trajectory and penalises those whose losses exceed the trajectory. The design of the AT&C loss trajectory involves judgements about the pace of achievable improvement that balances ambition (to create incentives for aggressive loss reduction programmes) with feasibility (to avoid setting targets that are technically unachievable given the current infrastructure condition and cannot be met even with maximum management effort).

B.7 Fuel and Power Purchase Cost Adjustment

The Fuel and Power Purchase Cost Adjustment (FPPCA) mechanism is the regulatory instrument used by most SERCs to allow distribution utilities to recover changes in the cost of bulk power procurement that occur between the tariff determination date and the current period, without requiring a full tariff revision proceeding. The FPPCA is typically implemented as a quarterly or monthly surcharge on the applicable tariff (expressed as a per-unit charge applied to all consumer categories), computed by comparing the actual cost of power purchase per unit during the adjustment period with the approved cost in the MYT order, with the difference (positive or negative) applied to the next period's tariff.

The legal and regulatory framework for FPPCA varies across states, reflecting the different approaches taken by SERCs to the

balance between tariff stability (which argues for infrequent adjustment of retail tariffs) and tariff cost-reflectiveness (which argues for prompt pass-through of power purchase cost changes). Some SERCs specify a "dead band" within which power purchase cost variations are not passed through (absorbing small fluctuations without tariff adjustment) but trigger the FPPCA for variations above the dead band threshold. Others specify a fixed computation methodology and timetable for the FPPCA regardless of the magnitude of the cost variation. The design of the FPPCA mechanism involves a judgement about the distribution utility's ability to absorb power purchase cost variations between adjustment periods without excessive financial stress, balanced against the cost to consumers of bearing the regulatory risk of delayed cost pass-through.

B.8 Power Sector Finances: Key Indicators

The financial health of India's electricity sector — and particularly the distribution utilities that constitute the weakest financial link in the sector's supply chain — is a critical determinant of the sector's ability to finance the investment needed for the energy transition. The aggregate financial indicators of the distribution sector reveal a picture of significant but highly variable financial stress across states, with a small number of utilities having achieved or approaching financial sustainability while the majority continue to operate with accumulated losses, large debts, and significant underpayment of dues to generating companies and state transmission utilities.

The aggregate AT&C loss for the country's distribution sector has declined to approximately 18–20 per cent in recent years, reflecting genuine progress but still representing a very large financial loss compared to best-practice levels. The gap between the average cost of supply and the average revenue realised per unit of electricity sold (the ACS-ARR gap) has narrowed in recent years but remains positive in many states, indicating systematic under-recovery of costs through regulated tariffs. The aggregate payables of distribution utilities to generating companies and transmission utilities — representing electricity supplied but not yet paid for — remain at several lakh crore rupees, creating financial stress throughout the supply chain and constraining the ability of generating companies to service their project finance debt.

EXTENDED ANALYSIS III

Renewable Energy Tariff: Bidding History and Policy Milestones

JNNSM, Competitive Rounds, Tariff Discovery, and International Comparisons

C.1 JNNSM Phase I: Setting the Solar Stage

The Jawaharlal Nehru National Solar Mission (JNNSM), launched in January 2010 under the National Action Plan on Climate Change (NAPCC), set the first serious national targets for solar energy capacity addition in India and established the competitive bidding framework that became the foundation of India's renewable energy procurement architecture. Phase I of the JNNSM targeted 1,000 MW of solar capacity through two competitive bidding rounds conducted by NTPC Vidyut Vyapar Nigam (NVVN).

The Batch I tariff-based competitive bidding under the JNNSM Phase I produced bids ranging from Rs. 10.95 per kWh to Rs. 17.91 per kWh for solar PV, with the lowest bids accepted up to the batch capacity ceiling. The tariff of Rs. 10.95 per kWh by some participants was itself a significant reduction from the CERC benchmark tariff of approximately Rs. 17–18 per kWh applicable at the time, demonstrating the ability of competitive pressure to drive below-benchmark tariff discovery even in an early-stage market with limited competitive participation. The 25-year PPA term and the Central Government guarantee backstopping NVVN's payment obligations provided the off-taker credit quality necessary to attract private investment in relatively large-scale solar projects in a nascent market.

Subsequent JNNSM batches and state-level solar procurement programmes in Rajasthan, Gujarat, and Andhra Pradesh progressively reduced the tariff discovered through competitive bidding, as the solar technology cost reduction curve steepened, the pool of experienced solar developers in India expanded, and access to debt finance at competitive rates improved as lenders became more comfortable with solar project credit risk. By 2015, the tariff for large ground-mounted solar projects in premium resource states had fallen below Rs. 5 per kWh; by 2017, below Rs. 3 per kWh; and by 2020, below Rs. 2 per kWh. This extraordinary tariff trajectory — a reduction of more than 80 per cent in 10 years — transformed solar from an expensive niche technology to the cheapest source of new electricity in India.

C.2 Wind Energy Competitive Procurement

The transition of wind energy procurement from SERC-administered regulated tariffs (under Section 62) to Central Government-administered competitive bidding (under Section 63) occurred somewhat later than for solar, reflecting the more distributed and site-specific nature of wind resource assessment and the more mature institutional framework already in place for wind project development under the Feed-in Tariff system. The first SECI Wind Tranche-I competitive bidding round, conducted in 2017, produced a tariff of Rs. 3.46 per kWh for 1,000 MW of wind capacity — below the CERC benchmark tariff of approximately Rs. 4.50–5.00 per kWh applicable at the time. Subsequent tranches continued to discover lower tariffs, and by 2021, wind tariffs had fallen to the Rs. 2.80–3.00 per kWh range.

The wind tariff reduction has been driven by improvements in wind turbine technology (larger rotor diameters and higher hub heights that increase annual energy production from the same site resource), falling wind turbine prices driven by competitive global manufacturing, and the increasing sophistication of wind resource assessment and project development practice in India. The introduction of hybrid wind-solar projects has further reduced the effective all-in tariff for combined renewable energy procurement, as the complementary generation profiles of wind and solar allow the combined project to achieve higher overall capacity utilisation factors than either technology alone.

C.3 Storage-Linked Renewable Tenders

The development of storage-linked renewable energy tenders — in which the developer commits to supply a contracted quantum of electricity during specific peak hours regardless of actual renewable generation, using battery storage to shift excess daytime solar generation to the peak evening hours — represents the most sophisticated evolution of India's competitive renewable energy procurement framework. SECI's Round-the-Clock (RTC) tenders and peak power supply tenders are the primary vehicles for storage-linked renewable procurement, requiring developers to design portfolios of wind, solar, and battery storage that can reliably deliver contracted energy during specified time windows throughout the year.

The tariff framework for storage-linked renewable projects under the competitive bidding framework involves unique design challenges. The contracted quantum of supply during peak hours must be specified clearly enough to define the developer's performance obligations without being so rigid that small variations in renewable generation or storage availability trigger excessive compensation claims. The payment structure must provide adequate revenue for both the renewable generation capacity (which earns revenue during all hours when it generates) and the battery storage capacity (whose costs can only be recovered during the peak hours when it provides firm supply). And the force majeure and change-in-law provisions must be calibrated to address the specific risks of storage-linked projects, including the risk of battery degradation and the risk of regulatory changes affecting the commercial value of storage services.

CERC has adopted tariffs for several RTC and peak power projects procured by SECI, establishing the regulatory precedent for this category of procurement. The adopted tariffs for peak power supply using storage-linked solar have been in the range of Rs. 5.50–7.00 per kWh for the guaranteed peak hours supply, reflecting the additional cost of battery storage relative to conventional solar procurement. As battery costs continue to fall and project developers gain experience with the design and operation of storage-linked projects, these tariffs are expected to decline progressively, potentially enabling the round-the-clock supply of renewable electricity at competitive rates with conventional dispatchable generation.

C.4 International Comparisons: RE Procurement Models

A comparative perspective on renewable energy tariff regulatory frameworks in other major markets provides context for understanding India's achievements and challenges in this domain. Several international comparisons are particularly instructive.

The United Kingdom's Contract for Difference (CfD) scheme provides renewable energy generators with a guaranteed "strike price" for electricity, with the generator receiving top-up payments from the national scheme when the wholesale market price is below the strike price and paying back the difference when the wholesale price exceeds the strike price. The CfD scheme effectively provides price certainty to renewable generators while ensuring that consumers benefit when wholesale prices are high.

The UK offshore wind CfD tariffs have fallen dramatically from over £150/MWh in the early CfD auctions (2015) to below £40/MWh in more recent rounds (2023), representing a cost reduction trajectory comparable to (though somewhat less dramatic than) India's solar tariff reduction. The CfD model, which directly links the regulatory tariff to the wholesale market price through a two-way contract-for-difference structure, is more sophisticated than India's fixed-tariff PPA model and provides better market integration for renewable generation.

China's renewable energy procurement framework has evolved from a feed-in tariff system to a competitive bidding system similar to India's Section 63 framework. China's scale of renewable energy procurement — adding over 200 GW of solar and wind capacity annually in recent years — has been the primary driver of global cost reductions in renewable energy technology, as Chinese manufacturing economies of scale have pushed down the cost of solar modules, inverters, and wind turbines to levels that have transformed the global energy economics of renewable energy. India's competitive renewable energy tariffs have directly benefited from this Chinese manufacturing cost reduction, as the majority of solar modules installed in Indian projects are manufactured in China.

C.5 Tariff Implications of Module Localisation

India's domestic content requirement (DCR) policy for solar energy — which requires that solar projects supported by certain government schemes use domestically manufactured solar cells and modules rather than imported (primarily Chinese) modules — has created regulatory tension between the objectives of energy cost reduction (best served by procuring the cheapest modules, currently from China) and domestic manufacturing development (served by requiring the use of higher-cost domestic modules). This tension has been extensively litigated, with several rounds of domestic content requirement challenges before CERC and APTEL, US and European challenges at the World Trade Organisation (WTO), and ultimately a Supreme Court decision addressing the regulatory framework for DCR solar projects.

From a tariff regulatory perspective, the DCR policy increases the tariff discoverable in competitive bidding for DCR projects relative to non-DCR projects, since domestic solar modules typically cost more than imported Chinese modules. CERC has addressed this differential by providing separate competitive bidding rounds for DCR and non-DCR projects, with the higher tariffs of DCR projects reflecting the higher cost of domestic modules. The regulatory challenge is to determine when and at what rate the premium for domestic modules should be phased out as domestic manufacturing capacity expands and achieves cost parity with imports — a judgement that requires balancing industrial policy objectives against tariff minimisation objectives.

C.6 Impact of Infrastructure Investment on RE Tariffs

The delivered cost of renewable electricity to distribution utility consumers depends not only on the generation tariff discovered through competitive bidding but also on the cost of transmission (both ISTS transmission to the state boundary and intra-state transmission from the ISTS substation to the distribution utility's load centres) and the distribution cost from the utility's network to the consumer premises. The total cost of renewable electricity supply, inclusive of all network costs, may be significantly higher than the generation tariff alone, and the regulatory treatment of network costs for renewable energy has significant implications for the economics of renewable energy deployment.

CERC's policy of waiving ISTS transmission charges for renewable energy generators for a specified period has been a significant

cost reduction measure for inter-state renewable energy procurement. The waiver reduces the delivered cost of renewable electricity to procuring distribution utilities by eliminating the transmission charge component (which can be Rs. 0.30–0.50 per kWh for long-distance inter-state transmission). However, the waiver also means that the ISTS transmission cost is allocated to other users (conventional generators and bulk consumers), creating distributional implications that have been the subject of inter-state regulatory controversy. The scheduled expiry of the ISTS waiver for existing RE projects raises the question of tariff revision: whether the generation tariff should be increased to compensate for the additional network cost that developers will face when the waiver expires, or whether developers should have priced this risk into their competitive bids.

EXTENDED ANALYSIS IV

APTEL Tariff Jurisprudence and Regulatory Principles

Leading Decisions on Cost Recovery, Change-in-Law, Open Access, and Consumer Rights

D.1 APTEL's Role in Tariff Regulatory Development

The Appellate Tribunal for Electricity (APTEL) has developed, over two decades of adjudication, a substantial and authoritative body of jurisprudence on electricity tariff regulation that has shaped the regulatory framework as profoundly as the Commission orders themselves. APTEL's decisions on appeals from CERC and SERC tariff orders have established the legal principles governing capital cost recovery, normative parameter determination, cross-subsidy computation, open access charges, change-in-law relief, and the many other legally complex questions that arise in the course of electricity tariff regulation. This body of jurisprudence, which now comprises thousands of orders and dozens of landmark decisions, is essential reading for practitioners who advise on electricity sector regulatory matters.

APTEL operates under Section 111 of the Electricity Act, 2003, which grants it exclusive appellate jurisdiction over all orders made by the Central Commission (CERC) and State Commissions (SERCs). The grounds for appeal to APTEL are not limited to questions of law; APTEL may examine both legal and factual aspects of the Commission orders it reviews, subject to the general principle of deference to the regulatory Commission's expertise on technical and commercial matters within its specialised domain. This broad appellate jurisdiction makes APTEL a significant force in shaping the regulatory framework: where Commission orders depart from established legal principles or make factual findings that are unsupported by the evidence, APTEL will typically set aside the order and remand for fresh determination, compelling the Commission to apply the correct legal framework.

D.2 Capital Cost and Rate Base Jurisprudence

APTEL has addressed capital cost recovery disputes in numerous appeals, establishing a coherent set of principles governing the regulatory treatment of project development and construction costs. The foundational principle is that regulated utilities are entitled to recover all costs that are prudently incurred in the development and construction of their regulated assets, where "prudent" means consistent with the standard of a competent and cost-conscious operator acting with reasonable care and diligence. Imprudent costs — costs that arose because the utility failed to exercise reasonable care, made commercially unreasonable decisions, or failed to take available cost-reduction measures — are not recoverable from consumers through the regulated tariff.

APTEL has applied the prudency standard to a wide range of capital cost items. Interest during construction (IDC) — the interest cost accruing on project loans during the construction period — is recoverable to the extent attributable to prudently managed construction timelines, but not to the extent arising from unreasonable delays that the generator should have been able to avoid. APTEL has established the principle that the "reasonable construction period" for the purposes of IDC computation is the period that a prudently managed project of the relevant type and size would require under normal conditions, without specific allowances for delays arising from the generating company's own management deficiencies (such as delays in procuring land,

obtaining approvals, or managing contractors).

The treatment of "additional capitalization" — capital expenditure incurred by the generating company after the initial commissioning of the plant, for purposes such as capacity augmentation, renovation and modernisation, environmental compliance upgrades, or the replacement of major equipment — has been addressed by APTEL in several decisions. The principle that has emerged is that additional capitalization is allowable in the tariff base where it is: technically necessary for the continued safe and efficient operation of the plant; prudently implemented at reasonable cost; consistent with the provisions of the CERC Tariff Regulations on additional capitalization; and beneficial to consumers by either improving the plant's availability or extending its operational life. Additional capitalization that constitutes a capability upgrade beyond the original plant design — effectively building a new generating asset at the consumer's expense within the shell of the original regulated asset — is subject to a more rigorous demonstration of prudency and consumer benefit.

D.3 Change-in-Law Jurisprudence

APTEL's jurisprudence on change-in-law (CiL) in electricity PPAs has developed through a large number of decisions addressing CiL claims arising from a wide range of regulatory and legislative changes. The leading cases address both the threshold question of what constitutes a qualifying CiL event under the applicable PPA provisions and the quantification question of the compensation or tariff adjustment payable to the affected party following a qualifying CiL event.

The Supreme Court's decision in Energy Watchdog v. Central Electricity Regulatory Commission & Ors (2017) — one of the most significant electricity regulatory judgements of the post-2003 era — addressed the question of whether a dramatic increase in the price of imported coal (arising from the Indonesian government's regulation of coal export prices from 2011 onwards) constituted a change-in-law event under the PPAs for the Mundra UMPP (Adani Power) and the Sasan/Tiroda projects (Reliance Power), entitling the developers to additional compensation from the distribution utility procurers. The Supreme Court held that changes in the regulatory regime of a foreign country (Indonesia) did not constitute a "change in law" within the definition of the relevant PPAs (which was limited to changes in Indian law), even though the price impact of the Indonesian regulation was severe and the generating companies could not have prevented or mitigated it. This decision had very significant commercial implications for the generating companies, who were denied the CiL relief sought and were required to absorb the massive fuel cost increase within the fixed competitive tariff of their respective PPAs.

The regulatory consequences of the Energy Watchdog decision prompted subsequent Central Government interventions to address the financial distress of the affected projects, including the renegotiation of certain PPA terms and the provision of additional coal linkages under the SHAKTI scheme. The decision also prompted a re-examination of the CiL provisions in standard PPA formats to ensure that future competitive bidding PPAs provide adequate coverage for material changes in international commodity prices that affect project economics, recognising that the rigid domestic-law-only definition of CiL in the earlier standard PPAs was too narrow to adequately protect competitive bidding projects from unforeseeable exogenous cost shocks.

D.4 Open Access and Cross-Subsidy Surcharge Cases

APTEL and the courts have addressed numerous challenges to the open access and cross-subsidy surcharge framework,

establishing principles that balance the Electricity Act's policy of promoting open access competition with the financial sustainability concerns of distribution utilities. The leading cases in this domain have addressed: the applicable surcharge rate for specific consumer categories claiming open access; the conditions under which the distribution utility can deny or limit open access applications; the treatment of "wheeling and banking" arrangements for captive power plants; and the regulatory treatment of consumers who exercise open access but subsequently seek to return to regulated supply from the distribution utility.

The principle that has emerged from APTEL's open access jurisprudence is that open access is a right conferred by the Act and cannot be refused by the distribution utility or the load despatch centre on commercial grounds unrelated to transmission or distribution capacity constraints. Where open access is refused on technical grounds (insufficient transmission or distribution capacity), the refusal must be supported by specific evidence of the capacity constraint and must be based on a transparent and non-discriminatory assessment of available capacity. Discriminatory or arbitrarily delayed processing of open access applications constitutes a violation of the utility's non-discrimination obligations under Section 42(2) of the Act and will be remedied by APTEL through directions to grant open access and potentially to pay compensation for the loss suffered by the applicant during the period of wrongful refusal.

D.5 Tariff Regulation and the Regulatory Compact

APTEL's consistent defence of the "regulatory compact" — the implicit understanding that regulated utilities will be allowed to recover their prudently incurred costs and earn a reasonable return in exchange for accepting regulatory control over their pricing — has been one of its most important contributions to the development of Indian electricity regulatory law. In multiple decisions involving distribution utilities whose tariff determinations by the SERC resulted in systematic under-recovery of costs, APTEL has held that a regulatory framework that fails to provide an adequate return on invested capital is inconsistent with the Electricity Act's objective of promoting investment in electricity infrastructure.

The regulatory compact cases have required APTEL to balance two legitimate but potentially conflicting regulatory objectives: the objective of protecting consumers from excessive tariff increases (which argues for setting the allowed return conservatively and rejecting imprudent cost claims) and the objective of maintaining the financial viability of the regulated utility (which argues for allowing the full recovery of prudently incurred costs and a fair return). APTEL has consistently held that both objectives must be pursued simultaneously: the Commission cannot achieve short-term consumer protection by setting tariffs below the level necessary for the utility's financial viability, since the medium-term consequence of regulatory under-recovery — utility financial stress, underinvestment, and service quality deterioration — ultimately imposes higher costs on consumers than a cost-reflective tariff would have done.

D.6 Consumer Rights and Regulatory Process

APTEL has also addressed numerous cases involving challenges to the regulatory process followed by the Commissions in tariff determination proceedings, establishing important principles of procedural fairness that have improved the quality of regulatory practice across the SERCs. The key procedural principles established through APTEL's jurisprudence include: the right of all parties affected by a tariff determination (including consumer groups, competing utilities, and open access users) to receive notice of the proceeding and an opportunity to participate; the obligation of the Commission to consider all substantive submissions made by parties, including consumer representations and objections; the requirement for a reasoned order explaining the basis for

each regulatory determination, including any departure from the utility's proposals; and the right of parties to cross-examine witnesses and challenge evidence in complex tariff proceedings.

These procedural principles have significantly improved the transparency and accountability of tariff regulatory proceedings in India. The requirement for reasoned orders — consistently enforced by APTEL through the setting aside of Commission orders that fail to provide adequate reasoning — has compelled the Commissions to engage seriously with all submissions made in the tariff proceedings and to articulate their regulatory judgements in a manner that is open to scrutiny and challenge. This transparency requirement has, in turn, improved the quality of submissions made by utilities and consumer groups, as all participants know that their arguments will be examined and addressed in the Commission's order and that inadequately supported submissions will be given little weight.

D.7 Emerging Regulatory Issues in APTEL Jurisprudence

APTEL's recent jurisprudence reflects the emerging regulatory issues of the energy transition period, including: the regulatory treatment of variable renewable energy generation in the despatch merit order; the tariff framework for battery energy storage systems; the CiL implications of GST for electricity sector projects; the regulatory treatment of stranded thermal capacity in the context of rapidly growing renewable penetration; and the application of the must-run dispatch principle to renewable generators under curtailment conditions. These emerging issues will shape the regulatory jurisprudence of the next decade as India's electricity sector undergoes its structural transformation towards a high-renewable, storage-integrated, and digitally managed energy system.

One particularly significant area of emerging APTEL jurisprudence is the treatment of renewable energy curtailment compensation. As renewable penetration has increased in several states and curtailment of must-run renewable generation has become more frequent, APTEL has begun to develop principles for the assessment of curtailment compensation claims. The emerging principles include: must-run renewable generators are entitled to compensation for generation curtailed for reasons other than grid safety; the compensation quantum is determined by the applicable PPA tariff applied to the curtailed generation; the liability for curtailment compensation is allocated between the distribution utility procurer and the state/regional transmission utility or system operator responsible for managing the transmission constraint that caused the curtailment; and the burden of proof lies with the system operator to demonstrate that any curtailment of must-run generation was justified by a specific, documented, and imminent grid safety concern rather than a commercial merit order decision. These emerging principles are establishing important regulatory accountability for curtailment decisions that affect the revenue of renewable energy developers and the economics of the energy transition.

EXTENDED ANALYSIS V

Electricity Tariff Regulation: Sector-Specific Frameworks

Hydro, Gas, Nuclear, Pumped Storage, and Cross-Border Tariff Issues

E.1 Hydroelectric Project Tariff: Distinctive Features

Hydroelectric projects present distinctive tariff regulatory challenges that differentiate them from thermal generating stations and require specialised provisions in CERC's regulatory framework. The fundamental difference is that a hydro project's output depends on water availability rather than fuel consumption: the "fuel" for hydroelectric generation is water, which is a natural resource not subject to market pricing, but whose availability varies seasonally and inter-annually in ways that cannot be fully predicted or controlled. This water availability variability creates challenges for: the definition of normative generation for tariff purposes (how much energy should a hydro project be expected to generate, given variable hydrology?); the incentive structure for the generating company (how should the financial consequences of below-normal hydrology be allocated between the generator and the procurer?); and the investment justification for large hydro projects (how can the generator be assured of adequate revenue in low-hydrology years to service its debt and earn a reasonable return on equity?).

CERC addresses the water availability problem through the concept of "Design Energy" for storage hydroelectric projects and "Normative Annual Energy" for run-of-river projects. The Design Energy for a storage project is the electricity generation achievable with 90 per cent dependable flow — the flow level that is equalled or exceeded in 90 per cent of years based on historical hydrology data. This conservative assumption ensures that the tariff is based on reliably achievable generation rather than average generation, providing the generating company with revenue certainty in most years. For run-of-river projects, the normative annual energy is specified based on the 50 per cent dependable flow, reflecting the more variable and less storable nature of river flows for projects without significant storage.

The tariff structure for hydroelectric projects under CERC's framework is specifically designed to accommodate the high capital cost and low operating cost characteristic of hydro projects. The fixed cost component (AFC) of the hydro tariff is higher as a proportion of total tariff than for thermal projects, reflecting the higher capital intensity of hydro infrastructure (tunnels, dams, powerhouses) and the near-zero variable cost (water is free at the source, though there are costs for operation and maintenance of the hydro equipment). The energy charge rate for hydro projects is correspondingly low, reflecting only the O&M cost of water management and plant operation rather than any fuel cost equivalent.

The distinction between primary energy (electricity generated within the Design Energy quantum) and secondary energy (electricity generated above the Design Energy in high-hydrology years) is an important feature of the hydro tariff framework. Primary energy is scheduled and despatched like conventional generation, with the procurer committed to purchasing it at the applicable tariff. Secondary energy, generated above the contracted design energy quantum in high-hydrology years, is sold at a mutually agreed tariff (typically lower than the primary energy tariff) or traded on the short-term market by the generating company, with the revenue shared between the generator and the procurer according to the terms of the PPA. This two-tier energy framework ensures that high-hydrology years generate additional revenue shared between the generator and consumers, while low-hydrology years do not result in revenue shortfall for the generator (since the AFC is payable based on availability rather

than generation).

Large hydroelectric projects in India — including the Tehri Hydro Development Corporation (THDC) projects in Uttarakhand, the NHPC projects across Himachal Pradesh, Jammu & Kashmir, and the northeastern states, and the National Hydroelectric Power Corporation (NHPC) portfolio — are regulated by CERC as central generating stations. The cumulative installed hydroelectric capacity in India is approximately 47 GW (including large hydro above 25 MW), representing about 12 per cent of total installed capacity but a significantly larger proportion of dependable firm capacity given the dispatchable nature of storage hydro projects. The development of new large hydro capacity has been slower than planned in recent years due to: the long development and approval timelines for large hydro projects in geologically and ecologically sensitive Himalayan river systems; the challenges of land acquisition and rehabilitation of displaced communities; the financial challenges of managing hydro project cost overruns and delays; and the competition from much faster-deploying and now cheaper solar and wind alternatives for base-load and peaking capacity needs.

E.2 Gas-Based Generation: Regulatory Challenges

Gas-based electricity generation — using natural gas or liquefied natural gas (LNG) as fuel in combined cycle gas turbines (CCGT) or open cycle gas turbines (OCGT) — occupies a distinctive and increasingly complicated position in India's electricity generation mix and regulatory framework. The development of gas-based generating capacity in India accelerated in the 2000s with the discovery of the Krishna-Godavari Basin (KG-D6) gas fields by Reliance Industries, which promised a large new source of domestic natural gas that could support the development of efficient combined cycle gas plants. Approximately 25 GW of gas-based generating capacity was developed in India on the basis of expectations about the availability of KG-D6 gas, but the subsequent dramatic decline in KG-D6 production from 2010 onwards — due to geological complexity and production difficulties that were not anticipated when the initial production sharing contract was signed — left most of this capacity stranded without adequate fuel supply.

The regulatory treatment of gas-based generating stations under CERC's tariff framework has had to address the unusual situation in which large amounts of installed generating capacity are either operating at very low plant load factors (because insufficient gas is available at acceptable prices) or not operating at all (because the gas price required to make operation viable exceeds the energy charge rate that the distribution utility procurers are willing to pay). CERC's tariff framework provides that gas-based generating stations receive their full AFC (fixed charges) as long as they maintain their declared availability, regardless of whether the gas fuel needed to actually generate is available and affordable. This availability-based compensation provides some financial protection to gas-based generators facing fuel supply uncertainty, but does not fully address the financial stress of stranded gas assets that cannot generate electricity because gas supply is unavailable or too expensive.

The Central Government has addressed the gas supply problem through the gas allocation framework administered by the Ministry of Petroleum and Natural Gas, which specifies the priority categories for domestic natural gas allocation (with the power sector receiving gas at the highest priority after the city gas distribution network). However, the volume of domestic gas available for the power sector has been insufficient to fully fuel the installed gas-based generating capacity, and the alternative of using imported LNG (which is significantly more expensive than domestic gas, typically 2–4 times the price) makes gas-based generation uncompetitive with coal-based and renewable generation in the current price environment.

The stranded gas capacity problem has been addressed through a combination of regulatory and policy measures: CERC orders allowing partial recovery of fixed costs for stranded gas plants on a "gas on water" basis (paying capacity charges for gas-based plants that maintain availability even when not generating); Ministry of Power schemes for procuring firm power from gas plants during peak demand periods using imported LNG on a government-to-government basis; and medium-term procurement of gas-based power during periods when LNG spot prices are low enough to make gas generation competitive. The long-term resolution of the gas capacity problem is linked to the availability of adequate domestic gas (dependent on the development of new gas fields including deep-water exploration and CBM/shale gas), the development of adequate LNG import infrastructure (including additional regasification terminals), and the renegotiation of gas-based PPAs to reflect the actual economics of gas-based generation in the current and projected future price environment.

E.3 Nuclear Power Tariff: Special Considerations

Nuclear electricity generation in India is confined to the public sector, with Nuclear Power Corporation of India Limited (NPCIL) and Bharatiya Nabhikiya Vidyut Nigam Limited (BHAVINI, the developer of the Fast Breeder Reactor programme) as the only licensed nuclear generating companies. The nuclear fuel cycle — from uranium mining, milling, conversion, enrichment (for pressurised water reactors), and fuel fabrication to spent fuel reprocessing and radioactive waste management — involves specialised government-controlled entities and does not involve market-based fuel procurement of the kind applicable to coal and gas stations.

CERC's tariff framework for nuclear generating stations follows the same basic cost-of-service methodology as for other central generating stations, with the AFC comprising depreciation, return on equity, interest on loans, working capital interest, and O&M expenses (including fuel costs calculated at the government-determined nuclear fuel price). The specific challenges of nuclear tariff regulation include: the treatment of decommissioning costs (the nuclear plant's end-of-life decommissioning is a major cost obligation for which regulatory provisions must ensure adequate funding during the plant's operating life); the regulatory treatment of spent fuel reprocessing and waste management costs; and the accounting for the long-term liability of radioactive waste storage.

India's nuclear generating programme is governed by the Atomic Energy Act, 1962 and is subject to the oversight of the Atomic Energy Regulatory Board (AERB) for nuclear safety. The AERB's safety requirements have a direct bearing on the capital costs and operating costs of nuclear generating stations, as nuclear safety upgrades mandated by AERB following the Fukushima accident (2011) required substantial additional investment in India's operating nuclear fleet. These post-Fukushima safety investments were reflected in the capital cost revisions of nuclear generating stations in CERC's subsequent tariff determinations, with CERC examining the prudency and necessity of each safety-related investment item before including it in the approved tariff base.

E.4 Pumped Storage Hydro: Emerging Regulatory Framework

Pumped storage hydroelectric projects — in which electricity is used to pump water from a lower reservoir to an upper reservoir during periods of low electricity demand and cheap electricity (typically at night or during periods of excess renewable generation), and the stored water is then released through turbines to generate electricity during peak demand periods — are attracting growing interest as India's renewable penetration increases and the need for flexible, dispatchable storage capacity grows. Pumped storage

offers several advantages over battery storage for large-scale, long-duration storage applications: much lower cost per unit of storage capacity for large projects; very long operational life (50+ years vs. 15–20 years for lithium-ion batteries); no degradation in storage capacity over time; and the use of established hydro technology with a long track record of reliable operation.

India has significant pumped storage potential, estimated at over 96 GW across various states, though only about 4.7 GW of pumped storage capacity is currently operational or under active development. The existing pumped storage projects were developed primarily for load balancing before the advent of large-scale renewable energy, but their role is now being reconceived as multi-functional flexible resources that can support renewable integration as well as providing peak capacity. CERC has recognised the growing importance of pumped storage in the context of renewable integration and has engaged with the regulatory framework questions arising from the dual character of pumped storage projects as both generation and consumption assets.

The key regulatory questions for pumped storage tariff determination include: whether a stand-alone pumped storage project (not associated with an existing hydroelectric project) should be regulated as a generation asset (with AFC-based tariff for capacity), as a transmission asset (if it primarily provides grid balancing services), or as a combined storage-and-generation asset with a bespoke regulatory framework reflecting its dual character; how the cost of electricity consumed in pumping should be treated in the tariff (whether as a project operating cost recovered through the pumped storage tariff, or as a market purchase whose cost passes through the tariff); and whether the pumped storage project should participate in the ancillary services market to earn additional revenue for grid balancing services, and if so, how the ancillary services revenue should be reflected in the tariff framework.

CERC has approved tariffs for some pumped storage projects on a competitive bidding basis under Section 63 and on a cost-based basis under Section 62, developing case-by-case regulatory frameworks that address the specific characteristics of each project. The Ministry of Power has also issued guidelines on the development and procurement of pumped storage projects, specifying that new pumped storage capacity should generally be procured through competitive bidding, with CERC adopting the competitively discovered tariff under Section 63. As India's pumped storage development programme accelerates, a more comprehensive and standardised regulatory framework for pumped storage tariff determination is expected to emerge through CERC's regulatory processes.

E.5 Cross-Border Electricity Tariffs

The regulatory framework for cross-border electricity trade — the import and export of electricity between India and its neighbouring countries — involves a unique intersection of electricity regulation, international trade law, foreign exchange regulation, and energy diplomacy. CERC has developed Guidelines for Cross-Border Trade of Electricity that provide the regulatory framework for commercial transactions involving the import or export of electricity through the interconnected electricity grids of India and its neighbours. These guidelines have been implemented for electricity trade with Bhutan, Nepal, Bangladesh, and (to a limited extent) Myanmar, and provide the basis for the expanding electricity trade relationships that are developing within the South Asian region.

The tariff framework for cross-border electricity trade addresses several specific regulatory questions. For electricity imports from Bhutan's hydroelectric projects — the largest source of electricity imports into India — the tariff is typically determined through bilateral negotiations between the Government of India and the Government of Bhutan, with the resulting tariff approved by

CERC as part of the inter-government electricity trade arrangement. The Bhutanese hydroelectric projects that supply electricity to India under the bilateral framework include the Chukha, Tala, Kurichu, and Punatsangchhu projects, with the tariff for each project reflecting the project's specific cost structure and the commercial terms of the bilateral agreement.

For electricity trade with Nepal, the tariff is determined through competitive procurement (Nepal selling surplus seasonal hydro power to India through NTPC's short-term purchase framework) or through bilateral negotiations for specific project-based imports. The growing volume of bilateral electricity trade between India and Nepal, including the commissioning of new 400 kV transmission lines that have significantly increased the cross-border transmission capacity, is expected to lead to a more formalised and comprehensive regulatory framework for India-Nepal electricity trade, potentially including a Power Purchase Agreement structure for long-term import of hydroelectric power from specific Nepali projects.

The Bangladesh electricity trade involves India exporting electricity to Bangladesh through dedicated transmission links (including the Baharampur-Bheramara 400 kV link and the Tripura-Bangladesh 132 kV links). The tariff for electricity exported to Bangladesh is determined through commercial negotiations between NTPC Vidyut Vyapar Nigam (NVVN) as the designated Indian electricity export entity and the Bangladesh Power Development Board (BPDB) as the Bangladesh off-taker, with the resulting tariff reflecting NVVN's blended procurement cost plus a trading margin. CERC's oversight of cross-border electricity trade includes the review and approval of the commercial framework for bilateral electricity trade, ensuring that the tariff terms are consistent with the applicable CERC guidelines and are not structured in ways that could create market distortions or undermine the financial interests of Indian electricity consumers.

E.6 Retail Tariff Design: Specific Consumer Category Issues

The design of retail electricity tariffs for specific consumer categories involves unique regulatory challenges that go beyond the general principles of cost allocation and cross-subsidy described earlier. This section examines the particular regulatory issues arising in the tariff design for three important consumer categories: railway traction, public water supply, and electric vehicle charging.

Railway traction — the electricity supply for Indian Railways' electric traction operations (electric locomotives and multiple units) — is a major electricity consumer accounting for a significant share of the load on distribution utilities in several states. The regulatory treatment of railway traction electricity has historically been a source of tension between the Ministry of Railways (which seeks the lowest possible electricity tariff for its traction operations) and the distribution utilities (which argue that railway traction should pay tariffs reflecting the full cost of supply, including the network costs associated with high-voltage direct connection to the distribution utility's grid at many traction substations). The development of the Indian Railways' own captive generation capacity (through long-term renewable energy contracts) and the proposal to establish Indian Railways as an open access consumer procuring electricity directly from the wholesale market represent strategic responses to the high electricity tariffs that railways face as large industrial consumers in several states.

Public water supply and sanitation (PWSS) utilities — which operate water treatment plants, pumping stations, and sewage treatment plants that are major electricity consumers in most Indian cities — face particular challenges in managing their electricity costs given the non-commercial nature of water pricing in India. Water supply utilities are typically regulated by state water regulatory authorities at tariffs that are set well below the cost of supply, with the resulting deficit covered by state

government budgetary support. The electricity cost component of the water supply utility's operating cost is therefore a significant fiscal liability for the state government, creating pressure on SERCs to set preferential electricity tariffs for PWSS utilities. Several SERCs have specified concessional tariff categories for PWSS, reflecting both the essential service character of water supply and the fiscal pressures on water utilities. The regulatory tension between the PWSS's claim for preferential tariff and the distribution utility's need for adequate revenue from its large PWSS loads is managed through negotiation in the SERC tariff proceeding.

Electric vehicle charging stations have been addressed by most SERCs through the specification of a dedicated EV charging tariff category, typically at commercial tariff rates with specific provisions for off-peak incentives and TOU pricing that incentivise charging during hours of low demand and abundant renewable supply. The design of EV charging tariffs has engaged the SERCs in novel regulatory questions about the appropriate classification of EV charging station operators (whether as distribution licensees, as bulk supply consumers, or as a new regulatory category of energy service provider), the applicable standards of service, and the technical requirements for bidirectional metering needed for vehicle-to-grid services. As EV adoption accelerates and EV charging becomes a significant load on the distribution network, the regulatory framework for EV charging tariffs will need to evolve rapidly to accommodate the new demands and opportunities that EV charging creates for the electricity distribution system.

E.7 Smart Grid Tariff Implications

The deployment of smart grid infrastructure — encompassing smart meters, advanced metering infrastructure (AMI), distribution automation systems, distribution management systems (DMS), and outage management systems (OMS) — creates both direct tariff implications (the cost of smart grid investment must be recovered through regulated tariffs) and indirect implications for tariff design (smart grid capabilities enable more sophisticated and consumer-responsive tariff structures). The regulatory treatment of smart grid investment costs, the recovery of smart metering costs from specific consumer categories versus socialisation across all consumers, and the design of tariff structures that leverage smart grid capabilities are active areas of regulatory development in India.

The cost recovery framework for smart metering under the RDSS scheme involves a combination of Central Government capital grant support (covering a proportion of the eligible capital cost for RDSS-approved smart metering projects) and regulated tariff recovery (for the balance of the capital cost not covered by the grant, included in the distribution utility's approved capital expenditure and recovered through the ARR). The allocation of smart metering costs between consumer categories raises specific regulatory questions: domestic consumers in lower income categories may benefit least from smart metering's features (such as TOU pricing and demand response) while still paying the allocated cost of the meter, creating equity concerns that some SERCs have addressed by recovering smart metering costs from a separate "smart meter charge" levied only on consumer categories with sufficient consumption to justify smart metering cost recovery.

The most transformative tariff implication of smart grid deployment is the potential for time-of-use (TOU) pricing to become the standard retail tariff structure for all consumers with smart meters, rather than just for large industrial and commercial consumers as at present. TOU tariffs that reflect the time-varying cost of electricity supply — with higher rates during morning and evening peak demand periods and lower rates during daytime solar generation periods and overnight low-demand periods — would provide significant efficiency benefits: incentivising consumers to shift flexible loads (washing machines, dishwashers, EV

charging) to off-peak periods, reducing peak demand and the associated generation and network capacity costs, and enabling consumers to reduce their electricity bills by adapting their consumption patterns to the tariff structure. The design of the TOU tariff schedule — specifying the peak, shoulder, and off-peak periods and the applicable price ratios — is a regulatory judgment that requires balancing economic efficiency with consumer equity and the administrative feasibility of implementation across a large and diverse consumer base.

E.8 Tariff Regulation and Energy Storage: Current Framework

The regulatory framework for electricity tariff in relation to energy storage is one of the most actively developing areas of CERC's regulatory programme. As battery energy storage systems (BESS) become increasingly cost-competitive and are recognised as essential flexibility resources for the integration of variable renewable energy, the need for a clear and comprehensive regulatory framework for storage tariff determination and market participation has become urgent. CERC has addressed storage tariff issues through a combination of project-specific tariff orders (for storage projects procured through competitive bidding under Section 63), consultation papers on the market participation framework for storage, and revisions to the grid code and ancillary services framework to accommodate the operational characteristics of storage systems.

The fundamental regulatory challenge for battery storage tariff design is the dual-use nature of storage: storage systems both consume electricity (when charging) and produce electricity (when discharging), and their commercial value derives from the price differential between the charge and discharge periods (energy arbitrage), the availability of the stored energy for system balancing (ancillary services), and the capacity value of stored energy for peak demand management (capacity market value). A tariff framework that compensates storage only for its energy output (like a generating station) fails to capture the full economic value of storage as a multi-service resource, potentially under-incentivising storage investment relative to the social value of storage in a high-renewable electricity system.

CERC's approach has been to procure storage on a competitive basis with a specific performance specification that defines the storage output required in terms of both power (MW) and energy (MWh) capacity, and the time window during which the storage must be available to deliver its contracted output. This approach allows the competitive bidding process to discover the tariff for the specified storage service, with the tariff covering the full cost of the storage asset — both the charging cost and the capital and operating cost of the storage system. The competitively discovered storage tariffs in India have fallen from approximately Rs. 10–12 crore per MWh in early procurements to below Rs. 6 crore per MWh in more recent tenders, reflecting the dramatic decline in lithium-ion battery costs driven by global manufacturing scale-up and technological improvement.

The regulatory treatment of storage connected to the distribution network — particularly "behind-the-meter" storage that is owned by individual consumers or communities and used primarily to reduce electricity bills and provide backup supply — raises different regulatory questions from utility-scale storage at the transmission level. Distribution-connected storage can provide value to the distribution network (by reducing peak demand and deferring network reinforcement) as well as to the individual consumer (by enabling peak demand management and backup supply). The regulatory framework must determine: whether the distribution utility can procure and own distribution-connected storage as a regulated asset (included in the ARR and recovered through tariffs); whether individual consumers can be compensated for the network value of their behind-the-meter storage; and how the interaction between behind-the-meter storage, net metering for rooftop solar, and the distribution utility's network management responsibilities should be regulated. These questions are at the frontier of distribution regulatory design globally and

are being actively examined by CERC and the SERCs in their strategic planning processes.

E.9 International Investment and Tariff Regulation

India's electricity sector has attracted significant foreign direct investment (FDI) in recent years, particularly in renewable energy generation. The regulatory framework's treatment of foreign investors in electricity projects — including the protection of their investment returns through regulated tariffs, the treatment of foreign currency revenue and hedging costs in the tariff framework, and the application of bilateral investment treaties (BITs) and free trade agreements (FTAs) to electricity sector investment disputes — has important implications for India's ability to attract and retain the foreign investment needed to finance the energy transition.

The foreign currency dimension of renewable energy project finance is a significant regulatory issue: many renewable energy projects procured through competitive bidding are partly or wholly financed through foreign currency loans or equity investments, exposing the project to foreign exchange risk (the risk that the Indian rupee will depreciate against the foreign currency of the loan, increasing the rupee cost of debt service). The PPA tariff, denominated in Indian rupees, does not automatically adjust for rupee depreciation, meaning that foreign currency-financed projects bear the full foreign exchange risk on their loan repayment. Some competitive procurement frameworks have attempted to address this issue by allowing bidders to submit tariff bids with a foreign currency linkage (a specified proportion of the tariff escalated in line with the applicable foreign exchange rate), but this approach increases the uncertainty of the tariff payable by distribution utility procurers and has not been adopted in the standard SECI bidding framework.

The bilateral investment treaty framework provides an additional layer of protection for foreign investors in Indian electricity projects, beyond the regulatory safeguards of the Electricity Act, 2003 framework. India's BITs typically include provisions for fair and equitable treatment, protection against expropriation, and investor-state dispute settlement through international arbitration. Regulatory changes that adversely affect the return on investment of foreign investors in regulated electricity assets — including changes to the tariff framework, the imposition of new taxes or levies, and changes to the open access or cross-subsidy framework — may in principle be challenged as BIT violations if they amount to unfair and inequitable treatment or indirect expropriation of the investor's legitimate expectations. India has faced several BIT arbitration claims relating to its electricity sector regulatory actions, and the development of the BIT framework for electricity regulation is an active area of international investment law that Indian electricity sector practitioners must understand.

E.10 Regulatory Capacity Building and Institutional Development

The effectiveness of India's electricity tariff regulatory framework ultimately depends on the institutional capacity of the regulatory commissions to develop and implement high-quality regulatory decisions. The institutional prerequisites for effective electricity regulation include: professionally competent commission members with expertise in electricity sector economics, engineering, law, and finance; a well-staffed technical and legal secretariat capable of processing complex regulatory submissions, preparing analysis to support commission deliberations, and drafting high-quality reasoned orders; adequate financial resources for commission operations, including competitive staff compensation, investment in regulatory information systems, and support for ongoing professional development; and a regulatory culture that values independence, technical rigour, transparency, and accountability in the exercise of regulatory authority.

The Forum of Regulators (FoR) has been an important institutional mechanism for building regulatory capacity across the SERCs by: facilitating the sharing of regulatory expertise and experience between commissions; developing model regulations and guidance notes that provide a starting point for regulatory development in specific domains; organising training programmes for commission staff; and maintaining a network of regulatory professionals across the country who can draw on each other's experience when facing novel regulatory challenges. The FoR's standards on information disclosure, consumer grievance redressal, and multi-year tariff design have progressively raised the baseline quality of regulatory practice across the country, even as significant variation in quality remains.

International collaboration through development institutions — particularly the World Bank, the Asian Development Bank (ADB), and bilateral development cooperation agencies of the UK, Germany, and other countries with experience in electricity regulatory reform — has provided important technical assistance and knowledge transfer to Indian electricity regulators. Programmes such as the India Power Sector Development Programme (supported by the World Bank), the South Asia Regional Energy Initiative (SARI), and bilateral regulatory cooperation programmes have provided: training and capacity building for CERC and SERC staff; advisory support for the development of specific regulatory frameworks (including renewable energy tariff design, smart grid regulation, and energy efficiency framework); and comparative regulatory analysis that has helped Indian regulators learn from the experience of comparable regulatory systems in other developing countries and in mature developed country markets. The sustainability of the regulatory capacity improvements achieved through these programmes — after the donor support ends and the Indian institutions must continue the development process with their own resources and capabilities — is the ultimate test of the institutional development achievement.

EXTENDED ANALYSIS VI

Tariff Regulatory Framework: Comprehensive Review

Competitive Markets, Infrastructure Finance, Consumer Welfare, and the Reform Path

F.1 Electricity Market Development: From Bilateral to Exchange-Based

India's electricity market has evolved from an almost entirely bilateral contractual structure at the time of the Electricity Act, 2003's enactment to a hybrid structure combining long-term bilateral PPAs (which remain dominant by volume) with a growing organised market segment traded through the power exchanges. This evolution reflects the progressive implementation of the Act's vision of competitive electricity markets and the growing maturity of market institutions, metering infrastructure, and market participant capabilities needed for efficient exchange-based trading. Understanding this market evolution is essential for practitioners who advise on electricity tariff and market regulation, as the interaction between the bilateral contract market and the exchange-based market creates complex tariff and commercial law questions.

The bilateral contract market for electricity in India encompasses: long-term PPAs of 20–25 years (under which the distribution utility is committed to procure a specified capacity from a designated generator at a fixed or escalating tariff for the contract period); medium-term bilateral contracts of 1–5 years (which allow distribution utilities to respond to medium-term supply gaps or procurement windows more flexibly than long-term PPAs); short-term bilateral contracts of less than 1 year (covering seasonal demand peaks, emergency procurement, and specific supply periods when the long-term PPA portfolio is insufficient or excess); and open access bilateral transactions (through which large consumers procure electricity directly from generators outside the distribution utility's supply portfolio).

The exchange-based market, operated by IEX and PXIL under CERC's Power Market Regulations, provides several distinct market segments designed to accommodate the diverse trading needs of electricity market participants. The Day-Ahead Market (DAM) operates through a uniform price double-sided auction in which buyers and sellers submit price-quantity bids for each 15-minute block of the following day, with the market clearing price determined at the intersection of the aggregated supply and demand curves. The Term-Ahead Market (TAM) allows participants to trade standardised weekly, monthly, and quarterly contracts for electricity delivery, providing forward price discovery and hedging opportunities for market participants with future exposure to electricity prices. The Real-Time Market (RTM), the newest segment launched in 2020, allows participants to trade electricity up to 15 minutes before delivery, enabling last-minute position adjustments and providing a market-based mechanism for balancing deviations from day-ahead schedules.

The Green Day-Ahead Market (G-DAM) and Green Term-Ahead Market (G-TAM), introduced in 2021, are dedicated renewable energy trading segments that allow solar and wind generators to sell their output through the exchange under simplified market access rules that accommodate the variable and unpredictable nature of renewable generation. The G-DAM operates on the same uniform price auction principle as the conventional DAM but is restricted to renewable energy generators and buyers who wish to purchase specifically renewable electricity. The Green Market segments provide price discovery for renewable electricity attributes separate from the REC mechanism, allowing buyers to purchase renewable electricity with attributes in a single transaction rather than separately procuring commodity electricity and RECs.

F.2 Market Coupling and Price Integration

The Market Coupling of the Day-Ahead Markets of IEX and PXIL, implemented in 2024, represents a significant advancement in Indian electricity market design that improves economic efficiency by ensuring that the same electricity is traded at a single uniform price across both exchanges rather than at potentially different prices reflecting fragmented liquidity. Market coupling is implemented through a common price discovery algorithm that aggregates the bid and offer schedules from both exchanges and solves for a single market clearing price that simultaneously clears the maximum possible volume across both exchanges at that price.

The economic benefits of market coupling include: elimination of the arbitrage opportunities that arise when different prices prevail on two exchanges trading the same commodity in the same delivery window; deeper market liquidity resulting from the combination of the two exchanges' order books, reducing price volatility and improving price discovery quality; and a more level playing field for market participants who previously had to decide which exchange to use for each transaction, potentially facing different prices depending on their choice. The implementation of market coupling required substantial regulatory work by CERC, including the development of a common market coupling algorithm, the coordination of the trading systems of IEX and PXIL, and the development of a settlement framework for cross-exchange transactions.

F.3 Capacity Markets: Design Considerations for India

The adequacy of electricity generation capacity — ensuring that enough firm, despatchable generating capacity is available to meet peak electricity demand with an appropriate reliability margin even during periods when renewable generation is unavailable — is one of the most important long-term governance challenges for India's electricity sector as it transitions to a high-renewable energy system. In energy-only markets (where generators earn revenue only for electricity actually generated and despatched), the investment in new despatchable generation capacity is driven by the expectation of revenue from periods of high electricity prices ("scarcity pricing") when demand approaches or exceeds available supply. As the proportion of variable, zero-marginal-cost renewable generation increases, the number of high-price hours in the energy market decreases (since renewable generation tends to moderate the energy price), potentially reducing the revenue available to despatchable generators and creating underinvestment in firm capacity.

Capacity markets address this investment adequacy problem by creating an explicit market for "capacity" — the obligation of a generating company to be available to generate electricity at specified times (particularly during peak demand periods) regardless of the energy market price. Buyers in the capacity market — typically the system operator or a designated entity on behalf of all consumers — procure a quantity of capacity commitment through a competitive auction, and the capacity price discovered in the auction provides an additional revenue stream for generators that reduces their dependence on energy market revenue to justify investment in new or continued operation of existing dispatchable capacity.

The design of a capacity market for India would need to address several unique features of the Indian electricity system. First, the dominance of long-term bilateral PPAs means that most generation revenue is determined through regulatory processes rather than market prices, and the introduction of a capacity market would need to interact carefully with the existing PPA-based revenue framework. Second, the large proportion of government-owned generating capacity means that investment adequacy is partially addressed through state planning and investment processes rather than purely through market signals. Third, the very

large variation in electricity demand across the national grid — from peak demand levels that are more than double minimum demand in some periods — creates design challenges for capacity obligations that must be specified at the level of regional or state electricity systems with different demand characteristics. Fourth, the cost of a capacity market — the additional payments to generators for their capacity availability — must be carefully weighed against the benefit of improved investment adequacy, particularly in the current context of significant excess conventional capacity in some regions.

F.4 Transmission Pricing and Renewable Energy Integration

The rapid expansion of India's renewable energy capacity is creating unprecedented demands on the transmission system and raising important questions about the interaction between transmission pricing regulation and the siting and operation of renewable energy generation. Renewable energy resources are distributed unevenly across India's geography: solar irradiation is highest in Rajasthan, Gujarat, Andhra Pradesh, and Telangana; wind resources are concentrated in Tamil Nadu, Andhra Pradesh, Gujarat, Karnataka, and Rajasthan; and large hydro resources are predominantly in the northeastern states, Himachal Pradesh, and Uttarakhand. The load centres that consume most of India's electricity are, by contrast, located in the more densely populated and industrialised states of Maharashtra, Uttar Pradesh, Delhi, West Bengal, and Tamil Nadu. The physical separation between major renewable resources and major load centres creates large inter-state power flows that must be accommodated by the transmission system, and the cost of transmission capacity to accommodate these flows is a significant component of the overall cost of renewable energy deployment.

The transmission pricing framework for renewable energy — particularly the waiver of ISTS charges for renewable energy generators — has been designed to reduce this cost burden and promote renewable energy development by eliminating the locational cost disadvantage of renewable generators in resource-rich but load-distant states. However, the ISTS charge waiver has important distributional implications: it reduces the cost of renewable energy to procuring distribution utilities but shifts the cost of the transmission system to other users (conventional generators and large consumers). As renewable energy's share of the generation mix grows, the proportion of ISTS users who are exempt from ISTS charges increases, concentrating the transmission cost recovery burden on a smaller and smaller group of non-exempt users. This dynamic creates an unsustainable trajectory for ISTS transmission cost recovery unless the charge waiver policy is reformed to ensure adequate cost recovery while maintaining incentives for renewable energy deployment.

The long-term reform of transmission pricing for renewable energy will likely involve some combination of: time-limited ISTS charge waivers (rather than permanent exemptions) with a defined phase-out schedule as renewable energy becomes cost-competitive without subsidy support; locational signals in the transmission charge framework that reflect the actual transmission cost impact of different generation and load locations, providing incentives for renewable developers to site their projects closer to load centres where transmission capacity is less constrained; and explicit transmission investment mechanisms (such as regulated asset base transmission tariffs for dedicated renewable evacuation infrastructure) that recover the cost of renewable transmission investment from the full pool of ISTS users rather than only from the directly benefiting renewable generators.

F.5 Regulatory Framework for Power System Flexibility

The increasing penetration of variable renewable energy in India's electricity system is creating growing requirements for power system flexibility — the ability of the electricity system to rapidly adjust generation output, demand, and storage

charging/discharging in response to variations in renewable generation and electricity demand. The regulatory framework for flexibility must create appropriate incentives for investment in flexible resources (including flexible thermal generation, pumped storage, battery storage, and demand response) and for the efficient dispatch of available flexibility in the spot market and ancillary services framework.

The current regulatory framework for flexibility in India is inadequate for the scale of flexibility that will be required as renewable penetration grows towards the 500 GW target. The primary flexibility mechanisms currently available include: the Deviation Settlement Mechanism (DSM), which penalises deviations from schedules at times of grid stress and creates an indirect incentive for flexibility; the Real-Time Market (RTM) at IEX and PXIL, which provides a near-real-time price signal for flexibility; and the ancillary services framework, which provides compensation for generators providing frequency support and reserve services. However, the DSM incentive is too blunt to efficiently procure the diverse range of flexibility services needed; the RTM is too small and liquid to provide adequate flexibility price signals at scale; and the ancillary services framework covers a relatively limited range of services and compensates them at regulatory rather than market prices.

CERC has recognised the inadequacy of the current flexibility framework and is actively developing a comprehensive flexibility regulatory framework through consultative processes. The proposed reforms include: development of a day-ahead and intra-day market for flexibility services, in which flexible generators, storage operators, and demand response aggregators compete to provide specified flexibility services at market-discovered prices; expansion of the ancillary services framework to cover a wider range of services including synthetic inertia (provided by large flywheels or advanced inverter controls), fast frequency response (provided by battery storage and pumped hydro), and sustained reserve (provided by flexible thermal generators and storage with longer discharge capability); and the development of a regulatory framework for flexibility aggregators, who aggregate the flexible capacity of multiple small generators, consumers, and storage units into a combined flexibility service offering that can participate in the flexibility market at the required scale and response speed.

F.6 Electricity Tariff and Environmental Costs

The environmental costs of electricity generation — including greenhouse gas emissions, air pollutants (particulates, sulphur dioxide, nitrogen oxides), water consumption, and land use — are not fully reflected in the current electricity tariff framework. The failure to internalise environmental costs in electricity prices creates a market distortion that systematically favours high-emission generation over low-emission alternatives, and imposes costs on society (through the health impacts of air pollution, the economic costs of climate change, and the costs of environmental degradation) that are not borne by the electricity consumers who create the demand for the generation. The correction of this market failure through the incorporation of environmental costs in electricity tariffs is an important dimension of the tariff reform agenda, though one that faces significant political and institutional challenges in the Indian context.

The most important tool for incorporating the environmental costs of electricity generation into prices is carbon pricing — the imposition of a charge on greenhouse gas emissions from electricity generation that reflects the social cost of the resulting climate change damage. India's Carbon Credit Trading Scheme (CCTS), introduced through the Energy Conservation (Amendment) Act, 2022, represents the first step towards domestic carbon pricing in the electricity sector, though the CCTS is designed as an intensity-based trading scheme rather than a cap-and-trade scheme, meaning that it creates relative incentives for emissions reduction but does not impose an absolute cap on electricity sector emissions. The CCTS's impact on electricity tariffs will

depend on the carbon credit price that emerges from market trading, which in turn depends on the stringency of the sector baselines and the supply and demand dynamics of the emerging carbon market.

The electricity sector's contribution to India's air pollution problem is substantial: coal-based power plants are major sources of particulate matter, sulphur dioxide, and nitrogen oxides that contribute to the high levels of air pollution in many Indian cities and rural areas. The Ministry of Environment, Forest and Climate Change's thermal power plant emissions norms, revised in 2015 with deadlines for compliance extended on multiple occasions, require coal power plants to install flue gas desulphurisation (FGD) systems, electrostatic precipitators or fabric filters, and selective catalytic reduction (SCR) systems for NOx control. The capital and operating costs of these pollution control systems are significant (estimated at Rs. 1–2 crore per MW for FGD alone), and their recovery through the regulated tariff — whether as a change-in-law capital cost addition or as a current-year operating cost inclusion — has been the subject of regulatory proceedings before CERC. The clean air costs of electricity generation, though not yet priced directly through environmental charges, are thus being progressively incorporated into regulated tariffs through the mandatory pollution control investment framework.

F.7 Power Purchase Agreement Standardisation

The standardisation of Power Purchase Agreement (PPA) terms through CERC's model PPA framework and the Ministry of Power's competitive bidding guidelines has been one of the most important regulatory contributions to improving the efficiency and predictability of electricity procurement in India. Model PPAs reduce transaction costs (by eliminating the need to negotiate fundamental commercial terms in each individual transaction), improve regulatory predictability (by ensuring that CERC's adoption proceedings under Section 63 deal with standard PPA terms rather than highly customised agreements), and facilitate project finance (by providing lenders with a standard document format with which they are familiar and whose risk allocation they understand).

CERC has issued model PPAs for the following categories of electricity procurement: central generating station cost-based tariff (the long-form model PPA for CERC-regulated generating stations under Section 62); competitive bidding under Section 63 for conventional thermal and large hydro projects; competitive bidding for solar PV projects (various sub-categories including ground-mounted utility-scale, floating solar, solar-storage hybrid); competitive bidding for wind projects; competitive bidding for wind-solar hybrid projects; competitive bidding for Round-the-Clock renewable energy projects; and the Long-Term Agreement model for power trading by SECI under its inter-state competitive procurement programmes. Each model PPA is tailored to the specific characteristics of the relevant procurement category, addressing the commercial, technical, and risk allocation issues particular to that category.

The evolution of model PPA terms over successive versions reflects the regulatory learning from the implementation experience of earlier generations of PPAs and from the regulatory disputes and APTEL jurisprudence arising from those PPAs. The specific provisions that have been revised in response to implementation experience include: the change-in-law provisions (to ensure adequate coverage of foreign law changes and commodity price changes); the force majeure provisions (to clarify the conditions triggering force majeure and the consequences of prolonged force majeure events, including the termination and compensation framework); the curtailment compensation provisions (to address the must-run status of renewable energy and the compensation for curtailment); the payment security provisions (to ensure adequate credit security through the letter of credit mechanism and the state government guarantee backstop); and the land acquisition provisions (to reflect the changed land acquisition cost and

risk allocation in the post-2013 land acquisition legislative framework).

F.8 Financial Health of Distribution Utilities: Regulatory Response

The aggregate financial position of India's state distribution utilities reflects the cumulative impact of decades of below-cost tariff setting, inadequate AT&C loss reduction, and insufficient state government subsidy payments. The aggregate losses of state DISCOMs — the accounting losses before interest, taxes, and depreciation — have grown to several lakh crore rupees over the past two decades, and the aggregate debt of state DISCOMs (the borrowings used to fund losses and capital expenditure) is estimated at over Rs. 6 lakh crore. The aggregate payables to generators and transmission utilities — representing electricity purchased but not yet paid for — have grown to a level that threatens the financial stability of the entire electricity supply chain.

The regulatory response to DISCOM financial stress has operated on multiple levels. At the tariff level, CERC and the SERCs have increasingly recognised the financial sustainability of the distribution utility as a legitimate regulatory concern that must be weighed alongside the consumer interest in affordable tariffs. The Forum of Regulators' guidance on distribution tariff regulation has consistently emphasized that regulatory frameworks must provide distribution utilities with a genuine opportunity to recover their approved costs and earn a reasonable return, rather than systematically approving ARRs at levels below the utility's actual prudent costs to avoid politically unpopular tariff increases. APTEL's jurisprudence on the regulatory compact (discussed in the Extended Analysis IV section above) has reinforced this principle at the appellate level.

At the scheme level, the Ujwal DISCOM Assurance Yojana (UDAY) scheme of 2015–2020 provided a structured framework for state governments to take over and restructure a large proportion of their DISCOMs' accumulated debt, converting the debt into state government bonds and thereby reducing the interest cost burden on the DISCOMs while obligating the state governments to commit to specific operational improvement targets. The operational improvement targets under UDAY covered AT&C loss reduction, ACS-ARR gap reduction, coal stock maintenance, and fixed asset register maintenance. While the debt restructuring component of UDAY was largely implemented, the operational improvement targets were achieved to a much lesser extent, with many states failing to achieve the specified AT&C loss trajectories and ACS-ARR gap reductions. The Revamped Distribution Sector Scheme (RDSS) of 2021 built on UDAY's experience, linking capital grant disbursement more tightly to the achievement of operational improvement milestones and providing a clearer accountability framework for state government commitment to DISCOM reform.

F.9 Tariff Proceedings: Procedure and Practice

The procedure for electricity tariff proceedings before CERC and the SERCs is a blend of adjudicatory and regulatory elements, reflecting the quasi-judicial character of the Commission's tariff-setting function. Understanding the procedural framework for tariff proceedings is important for practitioners who appear before the commissions on behalf of utilities, consumers, or other stakeholders. The major procedural phases of a typical distribution tariff proceeding before a SERC are described below.

Filing of tariff petition: the distribution utility files a tariff petition with the SERC specifying its proposed ARR for the MYT control period, supported by detailed cost projections, capital expenditure plans, AT&C loss trajectories, and a proposed retail tariff schedule. The petition must be filed in accordance with the Commission's regulations on information requirements and format, which typically specify the content and structure of the petition, the supporting data and analysis required, and the form

of any regulatory accounts submissions. The Commission's registry scrutinizes the petition for formal compliance and admits it for processing if it is formally compliant, or returns it for correction if it lacks required information.

Public notice and stakeholder engagement: following admission of the petition, the Commission issues a public notice inviting objections and suggestions from consumers, consumer groups, industry associations, and other interested parties. In most states, the public notice is published in leading newspapers and posted on the Commission's website; some commissions also conduct outreach to consumer groups, municipalities, and industry associations to encourage broad participation. The public notice specifies the deadline for filing objections and the date and venue of the public hearing at which the utility and objectors can present their cases before the Commission.

Written objections and the utility's reply: interested parties file written objections to the utility's tariff petition within the specified deadline. The content of objections typically addresses: the utility's cost projections (including challenges to specific cost items on grounds of imprudence or inflation); the proposed AT&C loss trajectory (with consumer groups often arguing for more ambitious loss reduction targets than the utility has proposed); the capital expenditure plan (with challenges to the necessity, scope, or cost of specific capital projects); and the cross-subsidy provisions of the proposed tariff schedule (with industrial consumer groups opposing high cross-subsidies and agricultural or domestic consumer groups seeking to maintain below-cost tariffs for their categories). Following receipt of objections, the utility is typically given an opportunity to file a written reply addressing the issues raised in the objections.

Public hearing and evidence: the Commission conducts a public hearing at which the utility's representatives present the petition and respond to questions from the Commission's members, and at which objectors can present their objections and engage in dialogue with the utility's representatives and the Commission. In complex tariff proceedings involving large utilities with many stakeholders, the public hearing may extend over multiple days and may involve technical presentations, expert testimony, and detailed examination of the utility's regulatory accounts. The Commission's members actively question the utility and the objectors during the hearing, probing the basis of specific cost claims and the justification for proposed tariff levels.

Commission deliberation and order: following the close of the proceedings, the Commission deliberates on the evidence and submissions and prepares a tariff order specifying the approved ARR, the applicable efficiency benchmarks and trajectories, and the retail tariff schedule. The tariff order must address all material issues raised in the proceedings and provide reasoned findings on each component of the regulatory determination. A well-reasoned tariff order typically runs to several hundred pages and may take several months to prepare following the close of the public hearing. The order is published on the Commission's website and distributed to the parties, and comes into effect on the date specified in the order (which is typically the commencement date of the new regulatory period or the date of the order itself for in-period tariff revisions).

F.10 Regulatory Outlook: India's Electricity Tariff Framework at an Inflection Point

India's electricity tariff regulatory framework stands at a significant inflection point, simultaneously managing the legacy challenges of DISCOM financial stress, cross-subsidy rationalisation, and agricultural metering reform while adapting to the transformative challenges of the energy transition, including massive renewable energy integration, storage deployment, EV charging management, and distributed energy resource governance. The regulatory framework's response to these concurrent challenges will determine whether India can achieve a clean, affordable, and reliable electricity system that supports its

development aspirations and climate commitments.

The most critical regulatory reform priorities for the near term include: completing the transition to universal smart metering and using the resulting data infrastructure to implement cost-reflective TOU pricing for large consumers; progressively implementing the DBT mechanism for electricity subsidies to replace cross-subsidies with targeted and transparent subsidies; strengthening the SERC framework to ensure that all state commissions are adequately resourced, professionally staffed, and genuinely independent to make evidence-based tariff determinations; developing a comprehensive regulatory framework for energy storage that provides appropriate investment incentives and market participation rules for battery and pumped hydro storage; and implementing the Green Energy Open Access Rules effectively in all states to enable large consumers to procure renewable energy at competitive prices.

The medium-term outlook for India's electricity tariff framework is one of progressive transformation from the current predominantly cost-of-service regulated, cross-subsidy-laden structure towards a more market-oriented, cost-reflective, and technology-neutral framework that provides appropriate incentives for the energy transition while ensuring that the benefits of cheaper renewable energy and improved market efficiency are shared equitably among all electricity consumers. The regulatory commissions — CERC and the SERCs — are the primary institutional vehicles through which this transformation will be managed, guided by the legal framework of the Electricity Act, 2003 and the policy direction of the National Electricity Policy and Tariff Policy. The quality and credibility of regulatory governance will be the decisive factor in determining whether India's electricity sector can attract the enormous investment required for the energy transition while maintaining the financial sustainability of the regulated utilities and the affordability of electricity for all segments of the population.

> **Summary: Tariff Regulation Key Principles**
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> India's electricity tariff regulatory framework rests on five foundational principles: (1) cost recovery — regulated utilities must be allowed to recover prudently incurred costs and earn a reasonable return; (2) efficiency — tariff mechanisms must create incentives for operational efficiency improvement and cost reduction; (3) equity — tariff structures must balance cost-reflective pricing with the provision of affordable electricity for lower-income consumers; (4) transparency — tariff determinations must be based on publicly available information, openly reasoned, and subject to effective regulatory and judicial oversight; and (5) sustainability — the tariff framework must ensure the financial viability of distribution utilities as a necessary condition for sustaining investment in electricity infrastructure. The ongoing evolution of India's tariff regulatory framework seeks to advance all five principles simultaneously in the context of the profound technological and market changes reshaping the electricity sector.

EXTENDED ANALYSIS VII

Tariff Regulatory Convergence and the National Policy Framework

Forum of Regulators, National Electricity Policy, and the Path to Coherent National Regulation

G.1 Forum of Regulators: Structure, Functions, and Achievements

The Forum of Regulators (FoR), constituted under Section 166 of the Electricity Act, 2003 as the national association of CERC and all State Electricity Regulatory Commissions, serves as the primary institutional mechanism for coordination among India's electricity regulators. The Forum is chaired by the Chairperson of CERC and includes the Chairpersons of all the SERCs as its members. The Forum's secretariat is provided by CERC, and its activities are funded through contributions from CERC and the SERCs. The Forum meets periodically — typically two to four times per year — to consider regulatory issues of common interest submitted by member commissions, the Central Government, state governments, or stakeholder groups.

The Forum's principal activities include: developing model regulations for adoption by SERCs covering subjects of national regulatory importance (including consumer protection standards, multi-year tariff principles, open access, renewable purchase obligation, and smart metering); facilitating the exchange of regulatory information and best practices among the commissions; preparing reports and recommendations on emerging regulatory issues for consideration by the commissions and the Central Government; and serving as a coordination forum for resolving inter-commission regulatory issues (including boundary disputes between CERC and SERC jurisdiction and harmonisation of standards applicable to inter-state transactions). The Forum's model regulations have been an important instrument for promoting regulatory convergence across the country, providing a baseline of common regulatory standards that reduces the inconsistency and fragmentation of the regulatory framework across states.

The FoR's model regulations on multi-year tariff design represent one of its most significant contributions to regulatory capacity building. The model MYT Regulations for distribution utilities specify a comprehensive framework for the conduct of MYT proceedings, including the information requirements for MYT petitions, the principles for setting efficiency targets and normative parameters, the mechanism for annual true-up, the framework for capital expenditure approval, and the procedure for mid-period tariff revisions. SERCs that have adopted the FoR's model MYT framework have generally developed more rigorous and consistent tariff regulatory processes than those that developed their own frameworks from scratch, reflecting the value of a common professional template in building regulatory capacity.

G.2 National Electricity Policy: Regulatory Implications

The National Electricity Policy (NEP), notified by the Central Government under Section 3(1) of the Electricity Act, 2003, establishes the overarching policy objectives and guidelines within which CERC and the SERCs are expected to exercise their regulatory functions. The NEP is binding on the Appropriate Commissions through the Section 61 requirement that tariff determination be guided by the NEP and the Tariff Policy. The current NEP, notified in 2005 and due for substantial revision to reflect the major changes in the electricity sector since then (including the renewable energy transformation, the smart metering programme, and the proposed retail competition reforms), sets out objectives including universal electricity access, reliable and

quality power supply to all consumers, minimum lifeline consumption for all households, financially sustainable utilities, and the development of competitive electricity markets.

The NEP's objectives create a framework of policy mandates that the commissions are required to pursue in their tariff and licensing decisions. The universal access objective requires SERCs to maintain affordable lifeline tariffs for domestic consumers at the lowest consumption levels while ensuring the financial viability of the distribution utility. The market development objective requires CERC to develop the regulatory framework for power exchanges, open access, and ancillary services that supports the transition from a fully bilateral to a more market-oriented electricity system. The financial viability objective requires SERCs to set tariffs at levels that genuinely cover the distribution utility's costs and provide a fair return, resisting political pressure to maintain below-cost tariffs that undermine the utility's financial health.

The NEP is expected to be significantly revised in the coming years to reflect the transformative changes in the electricity sector since 2005. The revised NEP will need to address: the integration of 500 GW of renewable energy and the associated grid management, storage, and flexibility requirements; the development of a competitive retail electricity market through content-and-carriage separation; the digital transformation of the distribution sector through smart metering and advanced distribution management; the emergence of electric vehicles, green hydrogen, and distributed energy resources as major new elements of the electricity demand and supply landscape; and India's climate commitments and the role of the electricity sector in achieving net zero emissions by 2070.

G.3 State Electricity Plans and Investment Adequacy

The National Electricity Plan prepared by the Central Electricity Authority under Section 3(4) of the Act provides the long-term generation capacity and transmission investment framework within which the regulatory commissions exercise their tariff and licensing functions. The NEP is prepared on a five-year basis and covers a ten-year planning horizon, specifying: the projected electricity demand by region and season; the capacity addition required to meet the projected demand with the specified reserve margin; the specific generation projects (both thermal and renewable) planned for commissioning in the planning horizon; the transmission investment required to connect new generation to load centres and to eliminate inter-regional congestion; and the fuel supply requirements for the planned thermal capacity addition.

The regulatory implications of the NEP for tariff determination include: the NEP's projections of power purchase costs for distribution utilities provide the basis for the Commission's assessment of power purchase cost prudency in distribution tariff proceedings; the NEP's transmission investment plan is reflected in CERC's approval of new ISTS projects and their incorporation into the transmission tariff framework; and the NEP's renewable energy capacity targets inform the SERCs' RPO specifications and the Central Government's competitive procurement programmes for renewable energy. The coherence between the national planning framework of the NEP and the decentralised regulatory decisions of CERC and the SERCs is important for ensuring that regulatory outcomes are consistent with national development objectives.

G.4 Electricity Pricing and Macroeconomic Impacts

The level and structure of electricity tariffs have significant macroeconomic implications through their impact on industrial competitiveness, manufacturing costs, consumer purchasing power, and inflationary pressures. Industrial electricity costs are a

major determinant of the competitiveness of energy-intensive Indian industries in both domestic and international markets: high electricity tariffs increase the cost of production for industries such as aluminium, steel, cement, chemicals, and textiles, reducing their competitiveness relative to producers in countries with lower electricity costs. The regulatory framework for industrial electricity tariffs must therefore balance the legitimate revenue recovery needs of the distribution utility against the competitiveness implications of high industrial tariffs, particularly in the context of India's manufacturing sector development aspirations under the Make in India programme.

The macroeconomic implications of electricity tariff regulation extend beyond direct manufacturing costs to the broader economy through the inflationary impact of electricity price increases. Electricity is an input into virtually all economic activities, and electricity tariff increases translate directly into higher production costs across the economy, contributing to inflationary pressure. The Reserve Bank of India's monetary policy framework takes account of electricity price changes as a component of the inflation dynamics that monetary policy must address. The sequencing and magnitude of electricity tariff revisions is therefore a matter of macroeconomic significance, not merely a sectoral regulatory question.

G.5 Renewable Energy Procurement and Grid Integration Costs

The total cost of integrating renewable energy into India's electricity system — the "system integration cost" of renewable energy — is significantly higher than the generation tariff alone, reflecting the costs of transmission infrastructure, balancing services, backup capacity, and system operation adaptations needed to accommodate the variable and geographically concentrated nature of solar and wind generation. A comprehensive accounting of renewable energy integration costs is essential for regulatory policy making, as decisions about renewable energy procurement, transmission investment, and storage deployment must be based on a realistic assessment of the total system cost rather than the generation cost alone.

The major components of renewable energy system integration costs include: the cost of transmission infrastructure to connect renewable generators in resource-rich areas to load centres (the Green Energy Corridor cost, estimated at approximately Rs. 0.30–0.50 per kWh of renewable energy transmitted over long distances); the cost of balancing services to manage the variability of renewable output (the DSM, ancillary services, and real-time market costs attributable to renewable variability, estimated at approximately Rs. 0.10–0.30 per kWh depending on the renewable penetration level); the cost of backup capacity to provide firm supply during periods when renewable generation is insufficient (the capacity cost of gas or flexible coal capacity held in reserve for this purpose, estimated at approximately Rs. 0.20–0.40 per kWh at current gas prices); and the cost of distribution network upgrades to accommodate the growing penetration of rooftop solar and other distributed energy resources at the consumer level.

The regulatory treatment of renewable energy system integration costs in the tariff framework has been inconsistent and incomplete. The ISTS charge waiver reduces the regulatory recovery of transmission costs from renewable energy transactions, effectively socialising these costs across all non-exempt ISTS users. The balancing costs of renewable variability are partly recovered through the DSM mechanism (charged to generating companies that deviate from their schedules) and partly socialised through the ISTS transmission tariff. The backup capacity costs are not specifically allocated to renewable energy procurement; they are included in the overall generation cost pool of the distribution utility's power purchase portfolio and recovered through the general electricity tariff. This fragmented and incomplete cost attribution makes it difficult for regulators and policymakers to accurately assess the true cost of renewable energy deployment and to make informed decisions about the optimal rate of renewable energy expansion.

G.6 Smart Meter Data Analytics and Regulatory Applications

The data generated by smart meters at scale — granular consumption records for potentially hundreds of millions of consumers, updated every 15 minutes — creates an extraordinary information resource for electricity tariff regulation. Smart meter data analytics can enable: more accurate demand forecasting for power purchase planning and tariff ARR computation; better assessment of distribution system losses (by comparing metered injection into the distribution network with metered consumer consumption and identifying the distribution of losses across network segments); identification of consumers with unusual consumption patterns that may indicate meter tampering, illegal connections, or operational anomalies; analysis of consumer demand elasticity that informs the design of time-of-use tariffs and demand response programmes; and evidence-based assessment of the consumer welfare impacts of tariff changes.

The regulatory application of smart meter data analytics by CERC and the SERCs is still in its early stages, constrained by: the limited deployment of smart meters to date; the absence of comprehensive data management systems capable of processing and analysing hundreds of millions of smart meter data streams; the lack of regulatory frameworks specifying how smart meter data can be used in tariff proceedings and what privacy protections apply; and the limited analytical capacity of regulatory commission staff to apply advanced data analytics techniques to regulatory questions. As smart meter deployment under the RDSS scheme progresses and data management systems are developed, the regulatory applications of smart meter data analytics will expand significantly, potentially transforming the information environment of electricity tariff regulation from one of chronic data deficiency to one of data abundance.

G.7 Land and Water in the Electricity Tariff Framework

The cost of land and water — the two physical resources most intensively used by electricity generating infrastructure — are important but often underappreciated components of electricity generation costs that have significant implications for the tariff regulatory framework. For thermal power plants, large amounts of water are required for cooling (either in open-cycle cooling towers that evaporate large quantities of water or in once-through cooling systems that abstract and return large volumes of river or coastal water); for hydro projects, the water itself is the fuel; and for solar and wind farms, the land on which they are installed must be acquired at market prices that vary enormously depending on location.

The regulatory treatment of land costs in the tariff framework for utility-scale solar and wind projects has been addressed in CERC's competitive bidding adoption proceedings, where questions have arisen about whether the land cost should be included in the approved capital cost (when projects procure land outright) or treated as an operating expense (when projects lease land from landowners). For projects developed on government land provided by state development corporations at concessional rates, the below-market land cost is effectively a subsidy that reduces the project's tariff compared to a project paying full market rates. The regulatory treatment of such land subsidies — whether they should be reflected in a lower approved capital cost for the project or treated as a government-provided benefit that flows through to the procurer through lower PPA tariffs — has implications for the financial modelling of projects and the comparability of tariffs across projects with different land cost structures.

G.8 Electricity Tariffs and Industrial Policy

The relationship between electricity tariff policy and India's industrial policy objectives creates significant tensions for regulatory commissions, which are mandated by the Electricity Act, 2003 to be guided by economic efficiency and consumer welfare principles in setting tariffs but are simultaneously subject to policy pressures to support specific industrial sectors through preferential electricity pricing. The tension between tariff regulation and industrial policy is evident in several contexts: the pressure from state governments to maintain low industrial tariffs to attract investment and support the competitiveness of existing industries; the demands from specific industrial sectors (such as aluminium, which is one of the most electricity-intensive industries) for tariff concessions that reflect their electricity cost sensitivity; and the use of electricity tariff preferences as a component of state industrial incentive packages designed to attract investment in specific geographical areas or industry clusters.

CERC and the SERCs have generally maintained the position that tariff regulation should be based on cost-of-service principles rather than industrial policy objectives, and have rejected demands for tariff preferences that are not justified by differences in the cost of supply to the relevant consumer category. However, the practical exercise of this principle has been complicated by the political sensitivity of industrial tariff decisions and the existence of multiple instruments (including exemptions from RPO, concessional open access provisions, and special economic zone tariff arrangements) through which state governments can provide electricity cost concessions to industrial consumers without directly intervening in the SERC's tariff proceeding. The legal and regulatory boundaries between legitimate industrial policy (which may include targeted electricity subsidies provided transparently through the Section 65 mechanism) and illegitimate regulatory interference (which would involve the Commission being pressured to set industrial tariffs below cost-of-supply for industrial policy reasons) are not always clear-cut and require careful regulatory judgment in each specific case.

G.9 Principles for Future Tariff Reform

Drawing together the analysis of this booklet, the following principles emerge as the foundation for a comprehensive reform of India's electricity tariff regulatory framework that would advance all the objectives of the Electricity Act, 2003 while managing the transition to a clean, competitive, and technologically advanced electricity system.

First, the principle of progressive cost reflection: retail electricity tariffs should progressively approach the cost of supply for each consumer category, with cross-subsidies reduced on a defined trajectory as the Direct Benefit Transfer mechanism for targeted electricity subsidies is implemented. This principle preserves the efficiency and equity objectives of the tariff framework while managing the political economy of cross-subsidy rationalisation through a transparent and predictable adjustment pathway. Second, the principle of transparent subsidy: all electricity subsidies should be explicitly provided by the state government through the Section 65 mechanism (or its DBT equivalent) rather than embedded in the tariff structure, making the cost of subsidies visible to the public, the legislature, and the regulatory framework.

Third, the principle of technology neutrality: the tariff and regulatory framework should not favour any particular technology for electricity generation, storage, or demand management over others, provided the technology meets applicable technical standards and safety requirements. Technology neutrality promotes competitive efficiency by allowing the cheapest technologies to succeed in the market on their merits, avoiding the regulatory lock-in of incumbent technologies that may become economically obsolete as the technology frontier evolves. Fourth, the principle of regulatory consistency: tariff decisions by CERC and the SERCs should be consistent with each other, with the legal framework of the Electricity Act, 2003, and with the policy framework of the National Electricity Policy and Tariff Policy. Regulatory inconsistency creates uncertainty for investors, increases transaction

costs, and undermines the credibility of the regulatory framework.

Fifth, the principle of regulatory accountability: all tariff determinations should be publicly explained in detailed reasoned orders, subject to effective appellate review by APTEL and the courts, and assessed against regulatory performance benchmarks that allow stakeholders to evaluate the quality of regulatory governance. Accountability requires not only procedural transparency but substantive quality in the regulatory decisions themselves — the demonstration through the reasoning of the tariff order that the Commission has considered all relevant evidence, applied the correct legal principles, and exercised its regulatory judgment in a manner consistent with the objectives of the Act. These five principles, consistently applied across CERC and all the SERCs, would provide the foundation for a tariff regulatory framework capable of supporting India's electricity sector through its transformative transition to a clean, competitive, and consumer-responsive energy system.

> **Booklet II: Key Takeaways**
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> India’s electricity tariff regulatory framework is founded on the cost-of-service methodology, implemented through CERC’s Terms and Conditions of Tariff Regulations for central generating stations and ISTS assets, and through the SERCs’ multi-year tariff framework for state distribution utilities. The framework has achieved significant successes including the development of independent regulatory institutions with genuine tariff authority, the implementation of competitive procurement for renewable energy (Section 63), and the progressive improvement of distribution utility performance benchmarking. The major ongoing challenges — DISCOM financial stress, cross-subsidy persistence, uneven regulatory capacity across states, and the emerging complexity of energy transition technologies — require continued regulatory reform guided by the principles of cost reflection, transparency, technology neutrality, consistency, and accountability established in the Electricity Act, 2003 and the Tariff Policy.

EXTENDED ANALYSIS VIII

Power Procurement, PPA Structures and Regulatory Instruments

Long-Term, Medium-Term and Short-Term Procurement; PPA Economics; Regulatory Safeguards

H.1 Power Procurement Planning by Distribution Utilities

The procurement of electricity by distribution utilities constitutes the single most consequential set of commercial decisions that shapes the cost of electricity for consumers over the long term. A distribution utility's power purchase portfolio — comprising long-term PPAs, medium-term contracts, and short-term purchases — typically accounts for 60–70 per cent of its total Aggregate Revenue Requirement. The decisions made today about what capacity to procure, from which technology, at what tariff, and under what contractual terms will determine the electricity costs that consumers pay over the next 25 years. The regulatory oversight of power procurement decisions — including the approval of procurement plans, the scrutiny of competitive bidding processes, and the assessment of procurement prudency in tariff proceedings — is therefore one of the most consequential functions performed by CERC and the SERCs.

The framework for power procurement planning by distribution utilities in India is structured around three elements. First, the Medium-Term Power Procurement Plan (MTPPP), prepared by each distribution utility for a horizon of 3–5 years and approved by the SERC, identifies the expected supply-demand balance in the utility's service area and specifies the additional capacity procurement needed to meet projected demand. Second, the Request for Proposal (RfP) or Request for Selection (RfS) for specific procurement tranches, prepared by the distribution utility (or by SECI on its behalf) and reviewed by the SERC for consistency with applicable guidelines, specifies the technical and commercial terms for the competitive procurement. Third, the tariff adoption petition filed by the distribution utility with the SERC after PPA execution, seeking the SERC's determination that the procured capacity is prudent and the tariff is consistent with applicable Tariff Policy principles, provides the regulatory approval needed before the PPA tariff can be recovered from consumers.

The regulatory challenges in power procurement planning include: the difficulty of accurately forecasting electricity demand over a 25-year PPA horizon in a rapidly evolving economy; the risk of over-procurement (which saddled many state utilities with expensive surplus capacity in the early 2010s when demand growth slowed below the level assumed when long-term PPAs were signed); the risk of under-procurement (which leaves the utility dependent on expensive short-term purchases at times of supply shortfall); the management of the transition from a predominantly conventional thermal generation portfolio to an increasingly renewable-heavy portfolio; and the financing of the large upfront capital costs of renewable energy procurement through capital grants, viability gap funding, or concessional finance.

H.2 Long-Term Power Purchase Agreements: Anatomy

The long-term Power Purchase Agreement between a generating company and one or more distribution utility procurers is the foundational commercial and legal instrument of the electricity supply chain in India. Understanding the structure, content, and regulatory treatment of PPAs is essential for practitioners who advise on electricity sector transactions and regulatory proceedings.

The following analysis examines the key provisions of a typical long-term PPA for a cost-based central generating station, noting the regulatory provisions that determine the tariff, the payment obligations, and the performance standards applicable to the parties.

The parties to a long-term PPA for a cost-based generating station are: the generating company (typically an NTPC subsidiary, a state government-owned generating company, or a private sector IPP) as seller; and one or more distribution utilities as buyers, typically allocated contracted capacity in specified proportions under a coordination agreement. The term of the PPA is typically 25 years from the commercial operation date (COD) of the generating station, consistent with the design life of the major generating equipment and the typical project finance repayment period. The contractual capacity is the MW of generating capacity contracted under the PPA; the normative annual energy entitlement (NAEE) is the energy that corresponds to the contracted capacity operating at the normative annual plant availability factor (NAPAF) specified in the PPA.

The tariff provisions of the PPA specify the Annual Fixed Charge (AFC) and Energy Charge Rate (ECR) that constitute the generator's tariff entitlement, consistent with the CERC Tariff Regulations applicable to the generating station. The AFC is payable by the procurers in proportion to their allocated contracted capacity, regardless of the generator's actual despatch, as long as the generator achieves its minimum normative availability. The ECR is payable per unit of energy actually scheduled from the generating station, subject to the generator having provided an accurate day-ahead generation schedule and complied with the despatch instructions of the Regional Load Despatch Centre. The billing and payment cycle for the PPA tariff is typically monthly, with the generator issuing monthly invoices to the procurers and the procurers making payment within a specified number of days of invoice receipt.

The payment security provisions of a long-term PPA are designed to protect the generator against the risk of procurer payment default. The standard payment security package for a central generating station PPA includes: an irrevocable revolving letter of credit (LC) in favour of the generator, issued by a scheduled commercial bank, covering a specified number of months' tariff equivalent (typically 1.25–1.5 times the average monthly AFC); a tripartite agreement between the generator, the procurer, and the procurer's state government (countersigned by the Reserve Bank of India), under which the state government undertakes to make good any payment default by the procurer within a specified cure period; and the right of the generator to draw on the LC in the event of payment default by the procurer, and to take additional measures (including reducing supply to the defaulting procurer) if the payment default continues beyond the specified cure period.

The change-in-law provisions of the PPA define the mechanism for adjusting the tariff (or compensating the generator) in the event of regulatory or legislative changes that materially adversely affect the project's economics after the PPA is signed. The standard CiL framework identifies a "base date" (typically the date of submission of the bid in the competitive procurement, or the date of CERC's tariff order for cost-based projects) and specifies that any change in the applicable laws or regulations after the base date that affects the generating company's cost or revenue constitutes a change-in-law event entitling the generator to relief. The quantum of CiL relief is the actual incremental cost or revenue impact attributable to the CiL event, computed on an incremental basis (i.e., the difference between the position with and without the CiL event).

H.3 Medium-Term and Short-Term Power Procurement

Medium-term and short-term electricity procurement — procurement for periods ranging from a few months to three years —

provides distribution utilities with the flexibility to manage their power purchase portfolio in response to near-term supply-demand developments without committing to 25-year contractual obligations. The legal framework for medium-term and short-term procurement is established by the Central Government's guidelines for short-term and medium-term procurement under the competitive bidding framework, the Ministry of Power's Short-Term Open Access regulations, and CERC's power trading framework. The power exchanges (IEX and PXIL) also provide liquid and transparent short-term markets for electricity procurement through the Day-Ahead Market, Term-Ahead Market, and Real-Time Market.

Medium-term procurement (typically 3 months to 3 years) serves several strategic functions for distribution utilities: it allows utilities to meet short-term supply gaps arising from the delayed commissioning of new long-term capacity; it enables utilities to take advantage of periods of competitive pricing by locking in medium-term supply at favourable tariffs; and it provides a mechanism for managing seasonal supply-demand imbalances (such as the additional supply needed during peak summer demand periods and the surplus that arises during monsoon season when hydro generation is high). The regulatory treatment of medium-term procurement in the ARR involves SERC approval of the utility's medium-term procurement plans and verification that the procurement terms are consistent with market conditions and do not represent imprudent purchases at above-market prices.

Short-term procurement through the power exchanges — the Day-Ahead Market (DAM) and Real-Time Market (RTM) — provides distribution utilities with daily flexibility to balance their contracted generation with actual demand. The DAM auction, in which distribution utilities and generators submit price-quantity bids for each 15-minute block of the following day, typically clears at prices that reflect the marginal cost of the least efficient generator despatched in each block. Distribution utilities use the DAM to: purchase additional power at times when their contracted generation falls short of their scheduled consumption; and to sell surplus contracted generation when their consumption is lower than contracted. The RTM provides a near-real-time equivalent of the DAM for last-minute position adjustments.

The procurement of electricity at distress prices — at very high prices during periods of acute supply shortage, such as during the extreme heat waves that have led to unprecedented demand peaks in recent years — raises important regulatory questions about cost recovery. When a distribution utility purchases very expensive short-term electricity to manage an emergency supply shortfall, the cost of this distress procurement may be far higher than the approved power purchase cost in the utility's MYT order. The SERC must determine whether to allow the additional cost to be recovered from consumers (through a truing-up of the power purchase cost variance) or to require the utility to absorb the cost internally (on the grounds that adequate long-term capacity procurement would have avoided the need for distress purchases). The regulatory treatment of distress procurement costs has been a significant and contested issue in several states, with utilities arguing for full pass-through and consumer groups arguing that utilities should bear the cost of their procurement planning failures.

H.4 Open Access Transactions: Legal and Commercial Framework

The open access framework established by Sections 38–42 of the Electricity Act, 2003 enables large electricity consumers and generators to access the transmission and distribution networks for the purpose of transacting electricity bilaterally without the intermediation of the distribution licensee. Open access is one of the most important competitive instruments in the Act's toolkit: it enables large consumers who are eligible for open access to negotiate directly with generators for competitive supply, bypassing the regulated tariff of the distribution licensee and potentially achieving significant cost reductions. The growth of open access in India has been significant but uneven, with open access more widely used in states with high industrial tariffs (creating a large cost

incentive for open access) and with relatively straightforward open access procedures.

An open access transaction involves: the generator and the consumer concluding a bilateral electricity supply agreement specifying the contracted volume, delivery period, and commercial terms; the consumer applying to the STU (for open access on the intra-state transmission system) or to the SLDC (for open access on the distribution network) for open access approval; the STU or SLDC verifying that sufficient transmission or distribution capacity is available for the proposed transaction and issuing an open access approval; the generator submitting the open access transaction schedule to the SLDC for inclusion in the state's daily generation schedule; the SLDC scheduling the open access transaction and managing any deviations through the Deviation Settlement Mechanism; and the consumer paying the applicable wheeling charge, cross-subsidy surcharge, and additional surcharge (for distribution network open access) or the applicable ISTS transmission charge (for long-term open access on the ISTS).

The development of a transparent, non-discriminatory, and efficiently administered open access framework is essential for the functioning of competitive electricity markets in India. The major barriers to effective open access include: the high cross-subsidy surcharge and additional surcharge in many states, which can reduce or eliminate the cost advantage of open access for consumers who pay high cross-subsidies under the regulated tariff; the slow and sometimes non-transparent processing of open access applications by state load despatch centres and state transmission utilities; the restrictions imposed by some states on the banking of open access energy, limiting the ability of consumers to manage seasonal demand variations through open access arrangements; and the uncertainty about the continuation of existing open access arrangements when the distribution licensee's long-term PPA portfolio changes or when the SERC revises the applicable surcharges.

H.5 Competitive Bidding Under Section 63: Procedure and Safeguards

The competitive bidding procedure under Section 63 of the Electricity Act, 2003, governed by the Central Government's guidelines for tariff-based competitive bidding, establishes a detailed framework for the procurement of electricity through transparent, competitive, and non-discriminatory processes. The procedure is designed to ensure that the tariff discovered through competitive bidding genuinely reflects market competition rather than collusion among bidders, favouritism in the evaluation of bids, or manipulation of the bidding process by the procurer or its advisors.

The key procedural safeguards in the competitive bidding framework include: the mandatory use of standard RfS/RfP documents that specify all material commercial terms (including the PPA terms, payment security requirements, and qualification criteria) in advance of bid submission; the requirement for a pre-bid conference and the provision of responses to bidder queries in advance of the bid submission deadline; the sealed bid process, which prevents procurers from informally encouraging lower bids from preferred bidders; the L1 (lowest bid) selection rule, which determines the successful bidder based solely on the tariff bid and the pre-specified qualification criteria; the post-bid opening transparency requirement, which requires that all bids be publicly opened and the results published; and the CERC review of the bidding process in the Section 63 adoption proceeding, providing regulatory scrutiny of the process even though CERC does not substantively evaluate the tariff level.

Allegations of manipulation or irregularity in specific competitive bidding processes have been the subject of regulatory proceedings before CERC and APTEL in a number of cases. The most common categories of alleged irregularities include: manipulation of the qualification criteria to favour specific bidders; post-bid negotiations between the procurer and the successful

bidder that alter the material terms of the bid (which is prohibited under the guidelines, as it would undermine the competitiveness of the process); error in the computation of the levelised tariff used to compare bids submitted with different escalation structures; and procedural departures from the mandated RfS/RfP process (such as extending the bid submission deadline without proper justification). CERC's approach in Section 63 adoption proceedings has been to satisfy itself that the bidding process was conducted in substantial conformity with the guidelines and that any departures were not material and did not affect the fairness of the process; CERC does not conduct a de novo evaluation of all aspects of the procurement but focuses on the most material procedural and substantive issues raised by interested parties.

H.6 Power Trading: CERC Licensing and Market Oversight

The electricity trading licence regime under Sections 12 and 52–64 of the Electricity Act, 2003, implemented through CERC's Power Trading Licence Regulations, creates a regulated framework for entities whose business involves the purchase of electricity for resale. Trading licensees play an important intermediary function in India's electricity markets, facilitating the matching of generators and procurers in the bilateral market, managing the credit and commercial risks of electricity transactions, and providing liquidity through active participation in the power exchanges. The regulatory framework for trading must balance the benefits of trading intermediation (lower transaction costs, better price discovery, and improved risk management for generators and procurers) against the risks of market power abuse, anti-competitive practices, and the systemic risk of a trading licensee default.

CERC's power trading licence regulations specify: the eligibility criteria for a trading licence (including minimum net worth, fit-and-proper character requirements for promoters, and the experience and competency requirements of management); the conditions of the trading licence (including limits on trading volumes for restricted category licensees, reporting requirements, and compliance obligations); the code of conduct for trading licensees (including the prohibition of market manipulation, the requirement for transparent pricing and billing, and the obligation to maintain adequate risk management systems); and the regulatory oversight mechanisms (including CERC's power to inspect the trading licensee's books, require information, and impose penalties for non-compliance).

The development of the trading segment in India has been significant, with the emergence of large trading licensees such as PTC India Limited (formerly Power Trading Corporation), NVVN, SEIL, MEIL, and a large number of smaller category-II licensees. The aggregate volume of electricity traded by licensed traders — comprising both the bilateral trading segment and the power exchange trading segment — has grown substantially since the early days of the Electricity Act, 2003 framework, reflecting the growing maturity of India's electricity market and the increasing comfort of generators and procurers with market-based rather than exclusively bilaterally-contracted supply arrangements.

H.7 CERC Adjudicatory Function and Regulatory Disputes

In addition to its tariff-setting function, CERC exercises a significant adjudicatory function under Section 79(1)(f) of the Electricity Act, 2003, which vests CERC with the responsibility of adjudicating disputes involving generating companies or transmission licensees whose inter-state activities give rise to the dispute. This adjudicatory function covers a wide range of commercial disputes arising from the implementation of electricity sector agreements and transactions, including disputes about the interpretation and performance of long-term PPAs, disputes about open access applications and transmission access terms,

disputes about the scheduling and settlement of energy transactions, and disputes about the commercial implications of force majeure events and change-in-law occurrences.

CERC's adjudicatory proceedings follow a quasi-judicial process that includes: the filing of a petition by the aggrieved party, supported by the relevant documents and evidence; the respondent's opportunity to file a reply; a hearing at which both parties can present their cases and respond to questions from the Commission; and the issuance of a reasoned order determining the dispute. The standard of review applied by CERC in its adjudicatory function is the determination of what is fair, reasonable, and consistent with the applicable contractual terms and regulatory framework, taking into account the commercial context in which the dispute has arisen and the broader policy implications of different possible resolutions.

APTEL has exercised significant influence on CERC's adjudicatory practice through its review of CERC adjudicatory orders on appeal. APTEL's decisions have established that: the principles of natural justice — including the right of each party to be heard and to receive a reasoned order — apply to CERC's adjudicatory proceedings as fully as to its tariff proceedings; CERC must apply contractual interpretation principles consistent with the Contract Act and the general principles of Indian contract law in adjudicating disputes about the meaning of PPA provisions; and CERC's discretionary judgments in adjudicatory matters (including judgments about reasonable timeframes for performance and appropriate relief for breach of contractual obligations) are entitled to regulatory deference from APTEL but are not immune from appellate review where they are clearly unreasonable or contrary to established legal principles.

H.8 Electricity Tariff in the Context of India's Energy Security

India's energy security — the reliable, affordable, and sufficient supply of energy to meet the country's development and security needs — is a critical dimension of national policy that intersects with electricity tariff regulation in multiple ways. Electricity tariff regulation directly affects energy security through: its impact on the financial health of electricity utilities, which affects their ability to maintain and invest in generation, transmission, and distribution infrastructure; its influence on the economics of domestic versus imported energy sources, which affects India's dependence on imported fuel; and its effect on the incentives for energy efficiency and demand management, which affect the aggregate energy requirement of the Indian economy.

The relationship between electricity tariff regulation and India's energy security is most acute in the domain of fuel security for thermal power generation. India imports approximately 200 million tonnes of coal annually (primarily for non-power uses such as steel and cement, but including some imported coal for power generation), and the import price of coal is subject to significant volatility driven by global supply-demand dynamics and the currency exchange rate. The regulatory framework for fuel cost pass-through in electricity tariffs — which allows thermal generators to recover actual fuel costs (subject to normative heat rate benchmarks) from consumers — means that global coal price volatility is transmitted to Indian electricity consumers through the energy charge component of the regulated tariff. This transmission of international commodity price volatility to domestic electricity consumers creates macroeconomic risks (electricity price inflation during coal price spikes) that the regulatory framework must manage through appropriate tariff adjustment mechanisms and fuel cost hedging requirements.

The rapid expansion of domestic renewable energy capacity is improving India's energy security by reducing dependence on imported fuel for electricity generation. The zero fuel cost of solar and wind generation means that a higher renewable share reduces the electricity system's exposure to international commodity price volatility, improving price predictability and reducing

the risk of sudden tariff increases driven by global fuel market developments. The regulatory framework for renewable energy procurement — through which CERC and the SERCs oversee the competitive bidding process and adopt the competitively discovered renewable energy tariffs — is therefore both a tariff regulation instrument and an energy security instrument, and the regulatory emphasis on competitive procurement, transparency, and long-term tariff certainty serves both objectives simultaneously.

H.9 Digital Transformation and Tariff Regulation

The digital transformation of the electricity sector — through the deployment of smart meters, digital distribution management systems, advanced analytics, and increasingly, artificial intelligence applications for grid management and demand forecasting — is creating both new opportunities and new challenges for tariff regulation. The opportunities include: better data availability for regulatory decision-making, reducing the information asymmetry between regulated utilities and regulatory commissions; new tariff products (including TOU pricing and demand response) that can improve allocative efficiency and reduce overall system costs; and the ability to monitor and verify utility performance against regulatory standards in near real-time rather than annually through submitted reports.

The challenges include: the need to design regulatory frameworks for new digital products and services (such as smart home energy management systems, EV charging services, and prosumer management platforms) that may not fit neatly into the existing consumer category and tariff structure framework; the regulatory treatment of digital infrastructure investments (smart meters, communication networks, data management systems) as capital expenditure eligible for inclusion in the regulated asset base; and the data governance and cybersecurity requirements that must be addressed in the regulatory framework for digital electricity infrastructure.

CERC and the SERCs have begun to develop regulatory frameworks for the digital transformation of the electricity sector, though the pace of regulatory development has generally lagged behind the pace of technology deployment. The Ministry of Power's RDSS scheme has provided a significant impetus for smart metering deployment, and the smart metering technical standards issued by the Bureau of Indian Standards and the CEA provide the technical baseline for the new metering infrastructure. The regulatory framework for data management, consumer privacy, and the use of smart meter data in tariff proceedings is still being developed, creating regulatory uncertainty that practitioners must navigate carefully on behalf of their clients.

H.10 Tariff Regulation and the Insolvency Code: A Recurring Interface

The intersection of the electricity sector's tariff regulatory framework with India's Insolvency and Bankruptcy Code, 2016 (IBC) has become an important and complex area of law, as several large electricity sector assets have been through or are undergoing the IBC resolution process. The regulatory dimensions of electricity sector insolvency include: the jurisdiction of the regulatory commission over a generating company that has been admitted to the National Company Law Tribunal (NCLT) under the IBC; the treatment of the PPA and its regulated tariff in the resolution plan; and the regulatory approval requirements for the new owner of the generating company following the resolution process.

The IBC's moratorium provisions (Section 14), which stay proceedings and enforcement actions against the Corporate Debtor

during the insolvency resolution process, create complex interactions with the electricity regulatory framework. The question of whether the CERC or SERC can exercise regulatory powers over a generating company that is subject to the moratorium — including the power to issue directions on technical performance, to modify approved tariff parameters, or to initiate proceedings for the revocation of its generation licence — is not fully resolved in the existing jurisprudence. The Supreme Court has held that Section 14's moratorium does not prevent regulatory authorities from exercising their statutory functions, but the precise scope of regulatory authority during the moratorium remains a developing area of law.

The treatment of PPAs in IBC resolution plans is one of the most commercially significant regulatory-insolvency interface issues. A resolution plan for a distressed generating company may propose modifications to the PPA terms — including the tariff, the contracted capacity, the payment security requirements, or the performance standards — as conditions for the feasibility of the resolution. Such modifications would require the approval of the procuring distribution utility and, ultimately, the regulatory commission that oversees the PPA. The question of whether the NCLT can approve a resolution plan that modifies regulated PPA terms without the approval of the relevant Commission has been addressed in several decisions, with courts generally holding that modifications to regulated tariff terms require regulatory approval even within the IBC framework, since the regulation of electricity tariffs is a statutory function of the Commission that cannot be overridden by the NCLT's jurisdiction under the IBC.

> **Booklet II: Comprehensive Coverage Summary**
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> This booklet has provided a comprehensive analysis of India's electricity tariff regulatory framework, covering: the economic principles underpinning cost-of-service regulation; CERC's detailed methodology for central generating station and ISTS tariff determination; the state-level MYT framework for distribution tariffs; the competitive procurement framework for renewable energy; network pricing for transmission and distribution; and the ongoing tariff reform agenda. Extended analyses have addressed the evolution of CERC regulatory practice, state-level experience, renewable energy bidding history, APTEL jurisprudence, hydro and nuclear special cases, market development, and the FoR's contribution to regulatory convergence. Together, these analyses provide practitioners with a thorough grounding in all aspects of electricity tariff law and regulation essential for advising on power sector transactions, regulatory proceedings, and policy development.