

ENERGY CONSERVATION AND AUDIT

BEE755B | AY 2026-27

MODULE 4: ELECTRICITY AS A COMMODITY & INDIAN POWER MARKET FRAMEWORK

LEARNING OBJECTIVES

After studying this module, you will be able to:

- ☐ Explain the distinguishing features of electricity as a commodity versus conventional goods
- ☐ Describe the four pillars of electricity market design: Imbalance, Scheduling & Dispatch, Congestion Management, and Ancillary Services
- ☐ Outline the framework of the Indian power sector including its structure, institutions, and regulatory bodies
- ☐ Explain the concept and components of Availability Based Tariff (ABT)
- ☐ Analyse the impact of ABT on grid discipline, commercial transactions, and frequency regulation in India

4.1 Electricity vis-a-vis Other Commodities

Electricity is unique among all traded commodities. Unlike wheat, oil, steel, or software, electricity cannot be stored economically in large quantities, travels at the speed of light, and must be produced and consumed simultaneously. These physical realities create fundamental challenges for market design and pricing that simply do not exist for conventional goods.

Understanding why electricity behaves differently from other commodities is the first step toward understanding why power markets require specialised rules, institutions, and regulatory frameworks.

4.1.1 What is a Commodity?

A commodity is a basic good or raw material that is interchangeable with other goods of the same type. Standard commodities share four properties:

1. **Storability** — can be warehoused to balance supply and demand over time

2. Transportability — can be physically moved from surplus to deficit regions
3. Homogeneity — units are identical regardless of source
4. Separability — production, transmission, and consumption are independent activities

Electricity satisfies homogeneity (a kWh is a kWh regardless of source) but violates the other three — and it is precisely these violations that make electricity markets uniquely complex.

4.1.2 Distinguishing Features of Electricity as a Commodity

Feature / Property	Conventional Commodities (e.g., Oil, Steel)	Electricity
Storability	Can be stored in tanks, warehouses, silos for months or years	Cannot be stored in large quantities economically; batteries/pumped hydro have very high costs and limited capacity
Simultaneous Production & Consumption	Production and consumption can be temporally separated by months	Must be produced and consumed at exactly the same instant — real-time balancing is mandatory
Transport Medium	Shipped via trucks, ships, pipelines with controllable routing	Flows via interconnected grid following Kirchhoff's laws — cannot be directed to a specific consumer; follows path of least resistance
Transportability	Transport losses are typically < 1% (pipelines) to ~3% (trucks)	Transmission losses: 3–8% in well-maintained grids; up to 20–25% in developing countries (India avg ~20% T&D)
Network Effects	No network effects — trading A's oil does not affect B's supply	Strong network externalities — one generator's output affects voltage and frequency throughout the grid (loop flows)
Demand Variability	Demand is relatively price-inelastic but smoothed by inventory	Extremely variable — daily peak:off-peak ratio can be 3:1 or more; seasonal variation up to 5:1 in some regions
Price Volatility	Prices are volatile but bounded by storage arbitrage	Spot prices can swing from near-zero (surplus RE) to thousands of Rs/kWh in shortage — no inventory buffer
Market Failure Risk	Markets generally self-correct via inventory and import/export	Without proper regulation, electricity markets fail via market power, cascading failures, or blackouts

Feature / Property	Conventional Commodities (e.g., Oil, Steel)	Electricity
Metering & Measurement	Straightforward physical measurement at point of exchange	Requires sophisticated real-time metering (SCADA, SAS, ABT meters) at every exchange point
Quality Uniformity	Quality varies (crude oil grades, steel specifications)	Quality strictly uniform — voltage, frequency, waveform — deviations cause equipment damage or grid failure
Substitutability	Other fuels (gas, coal) can substitute over weeks/months	No short-term substitute; end-use cannot change from electricity to another form in real time

Table 4.1: Electricity vs Conventional Commodities — A Comparative Analysis

4.1.3 Physical Laws Governing Electricity Flow

Electricity markets are constrained by immutable physical laws that do not apply to any other traded commodity:

Kirchhoff's Current Law (KCL): At any node, sum of currents flowing in = sum of currents flowing out (current cannot accumulate).

Kirchhoff's Voltage Law (KVL): The algebraic sum of voltages around any closed loop in a network = 0.

Implication for Markets: Electricity injected at one point redistributes itself across ALL parallel paths instantaneously — a trader cannot nominate a specific physical route. This creates loop flows, counter-flows, and congestion problems unique to electricity.

Physical Phenomenon	Description	Market Implication
Loop Flow	Power flows on unintended parallel paths when scheduled on a direct route	Transactions between two parties affect third-party networks; cross-border congestion
Frequency as Quality Signal	Grid frequency (50 Hz in India) reflects instantaneous supply-demand balance	Frequency deviation is the visible symptom of imbalance; market must respond in real time

Physical Phenomenon	Description	Market Implication
Reactive Power	Reactive power (VAR) maintains voltage; cannot be transmitted economically over long distances	Reactive support must be provided locally; creates local monopoly conditions for VAR providers
Short-Circuit Levels	Grid strength (fault level) determines stability margins and protection settings	Adding large renewable generation in remote areas weakens fault levels and requires grid reinforcement

Table 4.2: Physical Phenomena and Their Market Implications

4.1.4 Why Electricity Cannot be a Perfectly Competitive Market

Several structural features prevent electricity from behaving as a standard competitive commodity market:

Market Failure Cause	Explanation
Inelastic Demand	Consumers cannot respond to real-time price signals easily — no smart meters in most homes; lights and machines must remain on. This allows generators to exercise market power during peaks.
Essential Service	Electricity is not optional — hospitals, water utilities, transport cannot curtail. Governments must intervene to prevent blackouts regardless of market price.
Network Monopoly	Transmission and distribution wires are natural monopolies — it is inefficient to build parallel grids. Only generation and retail can be competitive; wires remain regulated.
High Capital, Long Lead Time	Power plants take 3-10 years to build with very high sunk costs. Investors need long-term revenue certainty, creating barriers to entry and exit.
Externalities	Environmental externalities (SO ₂ , NO _x , CO ₂ from thermal plants) are not automatically priced into the electricity market without regulatory intervention.

Table 4.3: Sources of Market Failure in Electricity Markets

NOTE: The above features explain why electricity markets worldwide are not purely deregulated — they operate under a mix of competition (in generation and retail) and regulation (in transmission and distribution). India's Electricity Act 2003 is based on exactly this hybrid framework.

4.2 Four Pillars of Electricity Market Design

Every electricity market — whether the UK Pool, Nord Pool, PJM (USA), or India's IEX — rests on four fundamental pillars. These are not optional features; they are engineering and economic necessities arising from the physical properties of electricity described in Section 4.1.

The Four Pillars of Electricity Market Design:

1. Imbalance Settlement — Who pays for real-time deviations from schedule?
2. Scheduling and Dispatch — Who generates how much, when, and in what order?
3. Congestion Management — What happens when the grid cannot carry all scheduled flows?
4. Ancillary Services — Who maintains frequency, voltage, and system security?

4.2.1 Pillar 1: Imbalance Settlement

Imbalance arises when a market participant's actual production or consumption differs from its scheduled (contracted) quantity. Since electricity must be balanced in real time, any deviation is automatically corrected by the system operator — but someone must pay for that correction.

(a) Definition and Types of Imbalance

Generation imbalance occurs when a generator produces more or less than its scheduled output. Load imbalance occurs when a consumer consumes more or less than its contracted draw.

Type of Imbalance	Who Creates It	Effect on Grid	Commercial Treatment
Over-generation	Generator produces more than schedule	Frequency tends to rise above 50 Hz	Generator paid at imbalance price (often lower than contract)
Under-generation	Generator produces less than schedule	Frequency falls below 50 Hz	Generator penalised — buys back deficit at imbalance price
Over-drawal	Consumer draws more than contracted	Frequency falls; stress on grid	Consumer penalised at UI (Unscheduled)

Type of Imbalance	Who Creates It	Effect on Grid	Commercial Treatment
			Interchange) rate under ABT
Under-drawal	Consumer draws less than contracted	Frequency rises; potential over-voltage	Consumer credited at UI rate

Table 4.4: Types of Imbalance and Their Commercial Treatment

(b) Imbalance Pricing Mechanisms

The price at which imbalances are settled is the most critical parameter in market design. The two main approaches are:

Mechanism	How It Works	India's Approach
Single Imbalance Price	One price for all deviations — positive and negative — based on balancing market marginal cost	Used historically under ABT (UI Rate linked to system frequency)
Dual Imbalance Price	Upward deviations priced differently from downward deviations to reflect system state (shortage vs surplus)	Proposed under newer CERC regulations for greater efficiency
Frequency-linked Rate	Imbalance price varies inversely with grid frequency — high price when frequency is low (shortage), low price when frequency is high (surplus)	Core of India's ABT — UI rate linked to real-time frequency measurement (see Section 4.4)

Table 4.5: Imbalance Pricing Mechanisms

(c) Importance of Imbalance Settlement

- Creates financial incentive for generators and loads to keep to their schedules
- Reduces the burden on system operator for real-time corrections
- Provides price signal for flexibility — dispatchable plants that can correct imbalances earn premium
- In India, the ABT framework converted imbalance from an invisible technical problem into a financially settled market transaction

$$\text{Imbalance Charge} = (\text{Actual Generation} - \text{Scheduled Generation}) \times \text{UI Rate (Rs/kWh)}$$

Where UI Rate depends on system frequency:

- If Frequency < 50 Hz (shortage): UI Rate HIGH (deters further under-generation)
- If Frequency > 50 Hz (surplus): UI Rate LOW (deters further over-generation)

4.2.2 Pillar 2: Scheduling and Dispatch

Scheduling and dispatch is the process by which the system operator determines which generators should run, at what output level, and at what time — to ensure that total supply exactly equals total demand at every moment while minimising cost and respecting technical constraints.

(a) The Distinction between Scheduling and Dispatch

Aspect	Scheduling	Dispatch
Time Horizon	Day-ahead or week-ahead	Real-time (every 15 minutes or less)
Purpose	Plan which units will run and approximate output levels for next day	Fine-tune actual output to maintain second-by-second balance
Output	Daily generation schedule (DGS) for each generator	Real-time dispatch instructions (automatic or manual)
Responsibility in India	RLDC/SLDC based on long-term access (LTA) and bids	RLDC/NLDC via automatic generation control (AGC) and manual instructions
Basis	Bilateral contracts, PPA commitments, spot market (IEX/PXIL) bids	Frequency deviation from 50 Hz, reserve activation

Table 4.6: Scheduling vs Dispatch — Key Distinctions

(b) Economic Dispatch

Economic dispatch is the optimisation problem of allocating load among available generators to minimise total cost while satisfying demand and operational constraints.

Objective: Minimise $\sum [C_i(P_i)]$ for $i = 1$ to N generators

Subject to: $\sum [P_i] = PD + \text{Losses}$ (power balance)

$P_{i_min} \leq P_i \leq P_{i_max}$ (generator limits)

Line flows within thermal limits (network constraints)

Where $C_i(P_i)$ = cost function of generator i at output P_i (Rs/hr)

The optimality condition (Lambda dispatch) requires that the incremental cost of the last unit of energy from each dispatched generator be equal — this is the system lambda (marginal cost):

$dC_1/dP_1 = dC_2/dP_2 = \dots = dC_N/dP_N = \text{lambda}$ (System Marginal Cost)

lambda = Locational Marginal Price (LMP) in nodal pricing markets

(c) Unit Commitment (UC)

Unit commitment is the longer-horizon scheduling problem of deciding which generating units to start up or shut down over a planning horizon (typically 24–168 hours), considering:

- ☐ Minimum up-time and down-time constraints (cannot start/stop a boiler every hour)
- ☐ Start-up costs (coal plant start-up can cost Rs. 10–50 lakhs in fuel)
- ☐ No-load costs (fuel consumed while running at minimum generation level)
- ☐ Ramp rate limits (MW/minute a generator can increase or decrease output)

Generator Type	Ramp Rate (MW/min)	Min Up/Down Time (hrs)	Start-up Time
Large coal (500 MW)	3 – 6	8 – 24 / 8 – 24	4 – 10 hours (cold)
Gas turbine (OCGT)	10 – 20	1 – 4 / 1 – 4	5 – 20 minutes
Combined Cycle (CCGT)	5 – 10	4 – 8 / 2 – 6	30 – 90 minutes
Nuclear	1 – 3	24–168 / 24–168	Several days
Hydro (reservoir)	50 – 200+	0 / 0	< 2 minutes
Battery Storage (BESS)	100% rated in ms	0 / 0	Instantaneous

Table 4.7: Generator Flexibility Characteristics Relevant to Unit Commitment

(d) Scheduling in the Indian Context

In India, the scheduling process under ABT follows a defined sequence for each day:

Step	Timing (Day D-1)	Action
1	By 10:00 AM on D-1	Generating stations submit advance declarations (AD) — expected generation for each 15-min time block (96 blocks/day)
2	By 3:00 PM on D-1	Long-term Access (LTA) holders nominate their drawl schedules; short-term traders submit bids
3	By 6:00 PM on D-1	RLDCs compile tentative schedules, check for violations (thermal limits, voltage), and circulate draft
4	By 10:00 PM on D-1	Final schedules issued; each generator receives its DGS (MW for each 15-min block)
5	Day D: Real-time	Actual generation and drawl metered every 15 min; UI charges computed based on deviation from schedule and frequency
6	D+3 to D+7	Energy accounting and commercial settlement by Nodal Agency (POSOCO/regional accounting); UI settlement bills raised

Table 4.8: ABT Scheduling Process in India

4.2.3 Pillar 3: Congestion Management

Transmission congestion occurs when the scheduled power flows on a transmission corridor exceed its thermal or stability limit. Congestion is a direct consequence of the laws of physics — electricity follows the path of least resistance and cannot always be directed where the market wants it to go.

(a) Nature and Causes of Congestion

- ☐ Structural congestion: Chronic under-investment in transmission infrastructure relative to generation
- ☐ Transient congestion: Temporary overloads due to unexpected plant outages or demand spikes
- ☐ Loop flow congestion: Power scheduled between two parties overloads a third-party corridor
- ☐ Reactive power constraints: Local voltage problems limit real power flow even when thermal limits are not binding

(b) Methods of Congestion Management

Method	Mechanism	Example / Used In
Nodal / Locational Marginal Pricing (LMP)	Different prices at each node — congested areas have higher prices;	USA (PJM, ERCOT), Australia (NEM), New Zealand

Method	Mechanism	Example / Used In
	price difference = congestion cost; efficient but complex	
Zonal Pricing	Grid divided into pricing zones; price differences between zones reflect congestion; simpler but less precise than nodal	Nord Pool (Nordic countries), EU internal market
Counter-trade / Re-dispatch	System operator instructs generator on one side to reduce and generator on other side to increase output; congestion charge socialised	Germany (costly — billions EUR/yr), India (limited use)
Transmission Rights (FTRs / CRRs)	Financial rights entitling holder to receive congestion revenue; hedges against price divergence between zones	USA (Financial Transmission Rights), India (Limited)
Curtailment / Redispatch (India)	Under CERC Order, congested corridors managed by curtailing long-term access holders or restricting bilateral trades	India: POSOCO manages Western/Northern interregional congestion

Table 4.9: Congestion Management Methods — International Comparison

(c) Congestion Management in India

India uses a transmission planning and access framework rather than market-based nodal pricing for congestion management:

- ☐ Long-Term Access (LTA): Generators/consumers book firm capacity on inter-state transmission (25 years); priority during congestion
- ☐ Medium-Term Open Access (MTOA): 3 months to 3 years access; lower priority than LTA
- ☐ Short-Term Open Access (STOA): Up to 1 month; curtailed first during congestion
- ☐ Transmission Charges: Recovered via Point of Connection (PoC) model — charges based on injection/drawal point on the network
- ☐ POSOCO (now NLDC/RLDC) manages real-time re-dispatch and curtailment orders when congestion occurs

NOTE: India introduced the 'Congestion Charge' framework under CERC Open Access Regulations 2008. A congestion charge = difference between day-ahead price at sink zone and source zone on IEX/PXIL. Revenue collected is redistributed to transmission licensees to fund grid augmentation.

4.2.4 Pillar 4: Ancillary Services

Ancillary services are the range of specialised services required to maintain reliable and secure operation of the power grid, beyond simply matching energy supply and demand. They are 'ancillary' to the primary energy service but absolutely essential for grid security.

(a) Categories of Ancillary Services

Service Category	Response Time	Function	Typical Provider
Primary Frequency Response (PFR)	0 – 30 seconds	Automatic turbine governor response to frequency deviations; arrests frequency decline	Thermal, hydro plants with governor enabled
Automatic Generation Control (AGC)	30 s – 10 min	Automatic secondary frequency control; restores frequency to 50 Hz after PFR acts	Hydro plants (fastest), gas turbines
Spinning Reserve	< 10 minutes	Unloaded capacity on already-running units; deployed to cover sudden plant outage	Part-loaded thermal/hydro generators
Non-Spinning / Supplemental Reserve	10 – 30 min	Offline capacity that can start quickly; backup if spinning reserve is depleted	Gas turbines (fast start), pumped hydro
Replacement / Tertiary Reserve	30 min – 4 hrs	Restores depleted spinning/non-spinning reserves over longer period	Slow-start thermal units, demand response
Reactive Power / Voltage Control	Continuous	Maintains voltage profile within statutory limits (+/- 5% in India); prevents voltage collapse	Generators, SVC, STATCOM, capacitor banks
Black Start Capability	On demand	Ability to start generating without external power supply after grid collapse	Hydro, diesel, gas peakers, battery
Demand Response (DR)	Seconds to hours	Large consumers reduce/shift load on operator command; equivalent to reserve	Industrial consumers, smart buildings

Table 4.10: Categories of Ancillary Services and Their Characteristics

(b) Ancillary Services in India

India's ancillary services framework has evolved significantly since 2010:

Year / Event	Development in Indian Ancillary Services
2010	CERC introduced Ancillary Services Regulation; initial focus on Spinning Reserve Regulation (SRR)
2013	Automatic Generation Control (AGC) pilot launched in Northern Region with NTPC Dadri; India became one of few countries to implement real-time AGC market
2015-16	AGC extended to all NTPC stations and state generators in Northern/Western Regions; ancillary charges separated from UI settlement
2019	CERC launched Ancillary Services Regulations 2019; defined Secondary Reserve Ancillary Services (SRAS) and Tertiary Reserve Ancillary Services (TRAS) with market-based procurement
2022-24	Demand-side participation in ancillary services enabled; BESS (Battery Energy Storage Systems) allowed to participate; integration with Real-Time Market (RTM) of IEX/PXIL

Table 4.11: Evolution of Ancillary Services Framework in India

NOTE: India's Automatic Generation Control (AGC) market allows generators to offer upward/downward regulation capacity. Deployed generators are paid AGC clearing price; consumers benefit from improved frequency and reduced imbalance charges.

(c) Frequency Standards in India

The grid frequency is the universal signal of supply-demand balance. CERC has specified the following frequency band requirements:

Frequency Range	Grid Condition	Regulatory / Commercial Action
Above 50.2 Hz	Over-supply	ABT UI rate = 0 (no incentive to generate more); possible curtailment of infirm power (wind/solar)
50.05 – 50.20 Hz	Near-surplus	Normal operation; UI rate low; mild incentive to reduce generation
49.95 – 50.05 Hz	Normal band	Target frequency; no special action; UI rate at notified neutral level

Frequency Range	Grid Condition	Regulatory / Commercial Action
49.70 – 49.95 Hz	Marginal deficit	UI rate rising; incentive for generators to increase output; loads penalised for over-drawal
49.50 – 49.70 Hz	Under-frequency	Under-Frequency Relay (UFR) alert zone; AGC activated; demand response triggered
Below 49.50 Hz	Distress / emergency	Automatic Under-Frequency Load Shedding (AUFLS); emergency actions; possible grid separation

Table 4.12: Grid Frequency Standards and Associated Actions in India (IEGC 2010 as amended)

4.3 Framework of the Indian Power Sector

The Indian power sector is the third-largest electricity system in the world by installed capacity and one of the most complex in terms of institutional structure, regulatory framework, and market design. Understanding its organisation is essential before studying market mechanisms like ABT.

4.3.1 Installed Capacity and Energy Overview

Parameter	2015-16	2020-21	2023-24 (Approx.)
Total Installed Capacity (GW)	298	383	~950
Thermal (Coal + Gas + Oil) (GW)	211	233	~240 (coal)
Renewable Energy (Wind + Solar) (GW)	43	94	~200+
Large Hydro (GW)	44	46	~47
Nuclear (GW)	5.8	6.8	~7.5
Per Capita Consumption (kWh/year)	1,010	1,208	~1,400+
Total T&D Losses (%)	~23%	~20%	~17–18%
Peak Demand (GW)	148.5	189.6	~243 (peak 2024)

Table 4.13: Key Statistics of Indian Power Sector (CEA / MoP data; approximate figures)

4.3.2 Vertical Structure of the Power Sector

The Indian power sector is structured as a vertically segmented value chain with distinct functions at each level:

Segment	Function	Key Players	Regulated / Competitive
Generation	Convert primary energy (coal, hydro, solar, wind, gas, nuclear) into electricity	NTPC, NHPC, NPCIL, State GENCOs, Private IPPs (Adani, Tata, Torrent, etc.)	Competitive (tariff determined by bidding / cost-plus for existing PPAs)

Segment	Function	Key Players	Regulated / Competitive
Transmission	Transport bulk power at high voltage (220 kV – 765 kV) over long distances	POWERGRID (PGCIL) at national level; STUs (State Transmission Utilities) for intrastate	Regulated monopoly (CERC/SERC sets tariff)
Distribution	Deliver power at low/medium voltage (33 kV and below) to end consumers	State DISCOMs (BESCOM, MSEDCL, TPDDL, etc.) — most are state-owned; some private (Mumbai, Delhi)	Regulated monopoly; retail tariff set by SERC
Trading	Buy and sell power commercially without owning physical assets	PTC India, NVVN, Adani Gas, private licensees; Power Exchanges (IEX, PXIL, HPX)	Licensed; margins regulated by CERC
System Operation	Real-time grid balancing, scheduling, dispatch, frequency control	POSOCO (now merged into NLDC/PGCIL) — NLDC, 5 RLDCs; SLDCs for intrastate	Regulated public service; cost-plus framework

Table 4.14: Vertical Segments of the Indian Power Sector

4.3.3 Key Institutions and Regulatory Bodies

Institution	Type	Role and Functions
Ministry of Power (MoP), GoI	Policy	National electricity policy, legislation (Electricity Act 2003), tariff policy, rural electrification (SAUBHAGYA, RDSS)
MNRE (Min. of New & Renewable Energy)	Policy	Solar, wind, biomass, small hydro policy and targets (500 GW RE by 2030)
CERC (Central Electricity Regulatory Commission)	Regulator	Tariff regulation for inter-state generation and transmission; open access; grid code (IEGC); market development (ABT, IEX licensing, ancillary services)
SERC (State Electricity Regulatory Commissions)	Regulator	Intrastate tariffs (retail, distribution, intrastate transmission); distribution franchises; state renewable obligations
NLDC (National Load Dispatch Centre)	SO / TSO	National grid management, scheduling, dispatch; frequency control; national grid security monitoring; reports to POSOCO/PGCIL

Institution	Type	Role and Functions
RLDCs (5 Regional LDCs)	SO / TSO	Regional scheduling, dispatch; ABT metering; open access coordination; manage 5 regional grids (NR, WR, SR, ER, NER)
SLDCs (State LDCs)	SO	Intrastate scheduling, dispatch; manage state grid; interface with RLDC for inter-state drawal
POWERGRID (PGCIL)	CTU / TO	Central Transmission Utility; own and operate inter-state EHV transmission network; long-term access (LTA) facilitation; NLDC host
BEE (Bureau of Energy Efficiency)	Regulator	Energy efficiency standards, PAT scheme, BEE star ratings, energy auditor certification under Energy Conservation Act 2001
CEA (Central Electricity Authority)	Technical	Technical standards for power plants and grids; national electricity plan; grid connectivity norms; data collection and statistics
IEX / PXIL / HPX	Market	Power Exchanges: Day-Ahead Market (DAM), Real-Time Market (RTM), Term-Ahead Market (TAM), Renewable Energy Certificates (REC)

Table 4.15: Key Institutions in the Indian Power Sector and Their Roles

4.3.4 Legislative Framework

Legislation / Regulation	Significance
Electricity Act, 2003	Landmark legislation replacing earlier Electricity Acts (1910, 1948, 1998); unbundled generation from T&D; enabled open access; created CERC/SERC; prohibited state monopolies on generation; enabled power trading and exchanges
Electricity (Amendment) Act, 2007	Minor amendments clarifying appellate tribunal jurisdiction and penalty provisions
National Electricity Policy, 2005	Set targets for rural electrification, renewable energy, T&D loss reduction, demand-side management
Tariff Policy, 2006 (amended 2016)	Mandated competitive bidding for new power procurement; allowed pass-through of fuel costs; provided for RPO (Renewable Purchase Obligation)
Energy Conservation Act, 2001 (amended 2022)	Mandated energy audits for DCs; empowered BEE; created PAT scheme; 2022 amendment added Carbon Credit Trading Scheme (CCTS)

Legislation / Regulation	Significance
Indian Electricity Grid Code (IEGC)	CERC regulation specifying technical and commercial requirements for grid connectivity; scheduling; ABT; frequency; outage coordination
CERC Open Access Regulations, 2008	Implemented open access to inter-state transmission; defined LTA, MTOA, STOA; congestion charges; banking of energy; charges and procedures

Table 4.16: Key Legislation Governing the Indian Power Sector

4.3.5 Power Markets in India

India has developed multiple market platforms for electricity trading:

Market Segment	Approximate Share of Total	Description
Long-Term PPAs (> 7 years)	~85%	Bilateral contracts between GENCOs and DISCOMs; competitive bid (tariff-based bidding, Case I/II) or cost-plus (legacy central sector)
Medium-Term Contracts (3 months – 7 years)	~3%	Direct bilateral deals between generators/traders and DISCOMs/open access consumers; negotiated tariff
Short-Term Contracts (< 1 year)	~4%	Spot bilateral deals, competitive bids by DISCOMs; cross-border trades (Nepal, Bhutan)
Power Exchange (DAM/RTM/TAM)	~7–8%	IEX Day-Ahead Market: uniform clearing price (UCP) auction; Real-Time Market (RTM): 48-block/96-block intraday; Term-Ahead Market (TAM): weekly/monthly contracts
Ancillary Services Market	< 1%	SRAS/TRAS for frequency regulation; growing with increasing renewable integration

Table 4.17: Power Market Segments in India (approximate, as of 2023-24)

NOTE: The share of short-term and exchange-based trading has grown from < 2% in 2003-04 to ~12% in 2023-24. As renewable capacity grows, short-term flexibility markets (RTM, ancillary services) will become increasingly important.

4.4 Availability Based Tariff (ABT)

Availability Based Tariff (ABT) is the tariff and scheduling framework introduced by the Central Electricity Regulatory Commission (CERC) in India beginning in 2000-01, as a mechanism to improve grid discipline, incentivise efficient plant operation, and create a quasi-market for short-term electricity imbalances.

CERC Definition: 'ABT is a frequency-based pricing mechanism for scheduling and commercial settlement of electricity in the Indian grid. It creates financial incentives for generators and beneficiaries to adhere to their schedules and discourages deviations that cause grid frequency disturbance.'

ABT was recommended by the K.P. Rao Committee (1999) and implemented by CERC through its Order dated 4 January 2000. It replaced the earlier 'flat-rate' energy exchange mechanism that had no financial consequences for over/under-drawal.

4.4.1 Background and Need for ABT

Before ABT, the Indian power sector suffered from severe grid indiscipline characterised by:

Problem (Pre-ABT, Pre-2000)	Impact on Grid and Markets
No scheduling mechanism	Generators ran at will; SEB utilities drew without prior intimation; no predictability for system operator
Massive over-drawal by state utilities	States drew 20-30% more than their share from the Central Sector — effectively stealing from other states; frequency fell to 48-49 Hz routinely
Flat energy charges	Whether a state drew at peak or off-peak, it paid the same average rate. No incentive to shift load or respect schedules.
Chronic low frequency	Indian grid operated at 48.8-49.5 Hz routinely; international norm is 49.9-50.1 Hz. Low frequency caused motor burnout, reduced efficiency, equipment tripping
No mechanism for surplus energy sale	If a state had surplus power at night, there was no way to sell it to deficit states commercially; energy wasted
Cross-subsidy distortions	Under-recovering DISCOMs drew maximum power regardless of cost; cost-efficient generation and load-shifting had no commercial reward

Table 4.18: Problems in Indian Power Sector Before ABT

4.4.2 Three Components of ABT

ABT restructures the tariff for central sector generating stations into three distinct components that together align commercial incentives with technical requirements:

$$\text{ABT} = \text{Component 1 (Capacity Charge)} + \text{Component 2 (Energy Charge)} + \text{Component 3 (UI Charge/Credit)}$$

Component 1: Capacity Charge (Fixed Charge)

The Capacity Charge (CC) is paid by the beneficiary states for the generator being available — irrespective of whether the generator actually generates electricity or not. It is analogous to 'booking a seat on a train' — you pay whether you sit or not.

Aspect	Details
Also Called	Fixed Charge (FC) or Normative Annual Plant Availability Factor (NAPAF) charge
Covers	Capital cost recovery (loan repayment + equity return), O&M expenses, insurance, overheads — costs that do not vary with generation level
Basis of Payment	Paid in proportion to declared availability (MW) — if generator declares it can generate but state does not schedule it, state still pays CC
Incentive Created	Generator motivated to maximise availability (maintain plant, avoid forced outages); beneficiary motivated to schedule fully to recover its CC payment
NAPAF (Normative)	85% for coal; 90% for gas (CCGT); 95% for run-of-river hydro — plant must declare availability at least at NAPAF to recover full fixed charge
Formula (simplified)	$CC_i = (\text{Installed Capacity}_i / \text{Total Capacity}) \times \text{Total Annual Fixed Cost} / 12$ [per month, per MW]
Typical Values (2023-24)	NTPC coal: Rs. 0.50 – 0.80/kWh (of normative generation); varies by station vintage and capital structure

Table 4.19: Capacity Charge — Component 1 of ABT

NOTE: The Capacity Charge creates the 'availability incentive'. If a plant is available but a state does not schedule it, the state still pays the fixed charge — motivating efficient scheduling and utilisation of committed capacity.

Component 2: Energy Charge (Variable Charge)

The Energy Charge (EC) is the payment for actual units of electricity generated and scheduled. It covers only the variable (fuel) costs of generation.

Aspect	Details
Also Called	Variable Charge (VC)
Covers	Fuel costs (coal, gas, oil), auxiliary energy consumption costs — costs that directly vary with generation quantity
Basis of Payment	Paid for every kWh actually scheduled and delivered — metered energy injection at generator bus bar
How Determined	Based on actual heat rate, calorific value of fuel, and fuel price index; adjusted periodically through fuel cost pass-through mechanism
Formula	$EC = (\text{Heat Rate} \times \text{Fuel Price} \times \text{Energy Generated}) / \text{Calorific Value}$ [Rs/kWh]
Typical Values (2023-24)	NTPC coal-based: Rs. 2.20 – 3.50/kWh variable charge depending on plant and coal price; imported coal higher
Incentive Created	Generator earns more EC by generating more; beneficiary incentivised to schedule generation when energy price < market alternative

Table 4.20: Energy Charge — Component 2 of ABT

Total Tariff Payment = Capacity Charge + Energy Charge

$$= [\text{CC Rate (Rs/MW/month)} \times \text{Declared Availability (MW)} \times \text{Months}] \\ + [\text{EC Rate (Rs/kWh)} \times \text{Scheduled Energy (kWh)}]$$

Note: Actual generation may differ from scheduled generation; difference settled via UI Charge (Component 3)

Component 3: Unscheduled Interchange (UI) Charge

The UI Charge is the most innovative and market-oriented component of ABT. It provides real-time financial incentives for maintaining grid frequency at 50 Hz by pricing deviations from schedule based on the prevailing grid frequency.

Aspect	Details
Definition	UI = Actual Generation (or Drawl) MINUS Scheduled Generation (or Drawl), measured every 15 minutes
Pricing Principle	UI Rate (Rs/kWh) is inversely linked to grid frequency — higher price when frequency is low (grid is short), lower price when frequency is high (grid has surplus)
Who Pays / Receives	Generator that over-generates at low frequency RECEIVES UI payment (rewarded for helping grid). Generator that under-generates at low frequency PAYS UI (penalised for worsening shortage). Symmetrically for beneficiaries.
Settlement Period	Every 15 minutes (time block) — 96 time blocks per day
UI Rate Notified By	CERC notifies UI rate vs frequency table; periodically revised to maintain incentive adequacy
Accounting	Regional accounting: RLDC computes UI for each entity; net UI position settled monthly via Nodal Agency (PGCIL/POSOCO)

Table 4.21: Unscheduled Interchange (UI) Charge — Component 3 of ABT

4.4.3 UI Rate vs Frequency Table

The UI Rate vs. Frequency relationship is the cornerstone of ABT's incentive structure. The following table shows the general form of this relationship (illustrative, based on CERC notifications; actual values revised periodically):

Grid Frequency (Hz)	UI Rate (Rs/kWh) [Illustrative]	Grid Condition	Effect on Market Participants
Below 49.50 Hz	8.00+	Severe shortage / distress	Very high penalty for over-drawers; extreme reward for additional generation
49.50 – 49.60 Hz	7.00	Significant deficit	Strong incentive for generators to increase output; high cost for over-drawers
49.60 – 49.70 Hz	6.00	Moderate deficit	Moderate incentive signals
49.70 – 49.80 Hz	5.00	Slight deficit	Mild incentive for corrective action

Grid Frequency (Hz)	UI Rate (Rs/kWh) [Illustrative]	Grid Condition	Effect on Market Participants
49.80 – 49.90 Hz	4.00	Near-normal (slight deficit)	Low-cost imbalance settlement
49.90 – 50.05 Hz	3.00 (neutral)	Normal operation (target band)	Neutral UI rate; no strong incentive to deviate
50.05 – 50.15 Hz	2.00	Near-normal (slight surplus)	Generators lose revenue from over-generation; loads benefit from cheap UI
50.15 – 50.20 Hz	1.00	Surplus	Generator penalised for over-generation; strong incentive to reduce
Above 50.20 Hz	0.00	Over-supply / infirm RE	No payment for additional units; curtailment signal

Table 4.22: UI Rate vs Grid Frequency (Illustrative; CERC notifies actual values periodically)

NOTE: The frequency-linked UI rate acts as an automatic real-time price signal. When frequency falls (shortage), the UI rate rises sharply — making it expensive for utilities to draw more and rewarding generators for producing more. This creates an automatic stabilising mechanism without manual operator intervention.

4.4.4 ABT Mechanism — Step-by-Step Worked Example

Worked Example: NTPC Ramagundam (500 MW unit) and Andhra Pradesh SEB

Assumptions for one 15-minute time block:

- Scheduled Generation (DGS): 450 MW | Actual Generation: 480 MW | Over-generation: +30 MW
- Scheduled Drawl (AP SEB): 200 MW | Actual Drawl: 230 MW | Over-drawl: +30 MW
- Grid Frequency during this block: 49.75 Hz | UI Rate at 49.75 Hz: Rs. 4.50/kWh (illustrative)

UI Energy = 30 MW x 0.25 hours = 7.5 MWh = 7,500 kWh

UI Amount = 7,500 kWh x Rs. 4.50/kWh = Rs. 33,750

Result: NTPC receives Rs. 33,750 from AP SEB for this 15-minute block.

AP SEB PAYS Rs. 33,750 as penalty for over-drawl at low frequency (worsening grid shortage).

NTPC RECEIVES Rs. 33,750 as reward for over-generation at low frequency (helping restore grid).

4.4.5 Implementation Timeline of ABT in India

Year	Milestone in ABT Implementation
1999	K.P. Rao Committee Report recommends ABT to address grid indiscipline; CERC drafts regulations
01 Jul 2000	ABT implemented for Western Region — first region in India; includes all central sector generators allocated to Western states
01 Apr 2002	ABT extended to Southern Region
01 Apr 2003	ABT extended to Northern and Eastern Regions; now covers all four synchronous regions of India
2006-07	CERC revises UI rates upward; introduces cap and floor on UI rate to prevent extreme price spikes
2010	CERC issues new IEGC 2010; tightens frequency band to 49.95-50.05 Hz; links UI rates to narrower frequency range
2012-13	ABT extended to include intrastate generators in several states (intra-state ABT / STABT); states adopt similar framework for their own generators
2015	CERC introduces 'Deviation Settlement Mechanism (DSM)' replacing UI for renewable generators; RE plants get separate DSM with gentler penalties to encourage RE growth
2022-24	Revised DSM regulations for RE/storage; integration with Real-Time Market (RTM) on IEX for sub-15 min balancing; ongoing reforms toward nodal pricing

Table 4.23: ABT Implementation Timeline in India

4.4.6 Impact and Achievements of ABT

Impact Area	Observed Outcome
Grid Frequency Improvement	Average grid frequency improved from ~49.0–49.2 Hz (pre-ABT) to 49.9–50.05 Hz (post-ABT); frequency violations reduced by 80%+
Grid Discipline	States became far more disciplined in scheduling and adhering to drawl schedules; instances of massive over-drawal declined sharply
Commercial Transparency	Energy exchanges between central generators and state utilities became commercially transparent; disputes reduced
Plant Availability	Central sector plant availability improved as generators were financially incentivised to maximise declared capacity
Surplus Power Trading	UI mechanism created a quasi-market for surplus power; states with surplus could 'sell' to deficit states at UI rates; eventually led to formal Power Exchange (IEX in 2008)
Revenue Metering	Forced installation of high-quality ABT meters at all generator buses and regional interconnections; improved data quality
Tariff Rationalisation	Separation of fixed and variable charges allowed rational economic dispatch; states procure power from cheapest available source during off-peak
Market Development	ABT UI mechanism was the precursor to India's power exchange — UI imbalances created spot price signals that IEX later formalised into Day-Ahead Market (DAM) prices

Table 4.24: Impact and Achievements of ABT in India

4.4.7 Limitations and Evolving Reforms

Despite its success, ABT has limitations that have prompted ongoing reforms:

Limitation	Reform / Response
Not suitable for Variable RE	Separate Deviation Settlement Mechanism (DSM) introduced for wind/solar plants; penalties calibrated to RE forecast uncertainty
15-minute granularity may be too coarse	Real-Time Market (RTM) on IEX launched (2020): 15-min blocks with intraday trading; quarter-hourly settlement proposed
No nodal pricing	CERC studying Locational Marginal Pricing (LMP) introduction; transmission constraints not reflected in ABT UI rates
State generators outside ABT	State ABT (STABT) introduced in most states but implementation quality varies; intrastate UI settlement weaker than central ABT

Limitation	Reform / Response
Gaming of declaration	Generators could game by over-declaring availability without intention to generate; CERC tightened actual vs. declared availability reconciliation

Table 4.25: Limitations of ABT and Reform Measures

4.4.8 Comparison: Pre-ABT vs Post-ABT Regime

Aspect	Pre-ABT (Before 2000)	Post-ABT (After 2000)
Tariff Structure	Two-part: fixed + variable; no real-time component	Three-part: capacity + energy + UI (frequency-linked)
Scheduling	No formal scheduling; utilities drew at will	Day-ahead scheduling; 96 time-block generation schedule
Surplus Power	No mechanism to sell surplus; wasted	Surplus sold at UI rate; later evolved into power exchange
Grid Frequency	Routinely 48.8 – 49.5 Hz; equipment damage common	Maintained at 49.9 – 50.05 Hz after IEGC 2010 tightening
Commercial Settlement	Opaque average rate; frequent disputes between SEB and NTPC/NHPC	Transparent; settled monthly by nodal agency with full accounting
Incentive for Efficiency	No incentive to operate efficiently or maintain plant	Strong availability incentive; plant availability improved to 85%+ consistently
Market Development	No spot market; no price signal	UI rates provided quasi-spot prices; IEX DAM/RTM evolved from ABT

Table 4.26: Pre-ABT vs Post-ABT Comparison

Module 4 — Summary

This module has covered the foundational concepts of electricity as a unique commodity and the institutional and market framework of the Indian power sector. The key takeaways are:

5. Electricity is distinguished from other commodities by its non-storability, simultaneous production-consumption requirement, network externalities (Kirchhoff's laws), extreme demand variability, and its essential-service character — all of which necessitate regulated and carefully designed markets.
6. The four pillars of electricity market design — Imbalance Settlement, Scheduling and Dispatch, Congestion Management, and Ancillary Services — address the physical realities of the grid and convert technical requirements into commercial incentives.
7. The Indian power sector is structured as a vertically segmented value chain (Generation, Transmission, Distribution, Trading, System Operation) governed by CERC/SERC regulations under the Electricity Act 2003. Key institutions include NLDC/RLDC, POWERGRID, IEX, PXIL, BEE, and CEA.
8. Availability Based Tariff (ABT) — introduced by CERC in 2000 — replaced ad-hoc energy exchange with a transparent three-part tariff (Capacity Charge + Energy Charge + UI Charge). Its frequency-linked UI rate converted grid frequency into a real-time price signal.
9. ABT dramatically improved Indian grid discipline: frequency stabilised from 48.8-49.5 Hz to near 50 Hz; over-drawal by states reduced; central sector plant availability improved; and the UI mechanism eventually spawned India's formal power exchange (IEX).
10. ABT limitations — particularly for variable renewable energy — have been addressed through Deviation Settlement Mechanism (DSM) for RE, Real-Time Market (RTM), and ongoing CERC reforms toward nodal pricing and sub-15 minute settlement.

Module 4 — Review Questions

Short Answer Questions:

11. List any five distinguishing features of electricity as a commodity compared to conventional goods like oil or steel.
12. Explain why electricity markets cannot be perfectly competitive. Discuss any three structural causes.
13. What is an 'imbalance' in electricity markets? How does frequency-linked imbalance pricing create grid discipline?
14. Differentiate between scheduling and dispatch in the context of the Indian power sector.

15. What is economic dispatch? Write the optimality condition (Lambda condition) and explain its physical meaning.
16. Explain the concept of congestion management. Compare nodal pricing with counter-trade as methods.
17. Define ancillary services. List six types with their response time and primary function.
18. What were the main grid problems in India before ABT? How did each component of ABT address these problems?
19. Explain the three components of ABT with the formula for total tariff payment.
20. How is the UI rate linked to grid frequency? Explain with illustrative values from the UI Rate vs Frequency table.

Long Answer / Analytical Questions:

21. 'Electricity is unique among all commodities.' Critically examine this statement with reference to its physical, economic, and regulatory implications. (10 marks)
22. Explain the four pillars of electricity market design. For each pillar, describe the problem it addresses, the mechanism used to solve it, and its implementation in the Indian context. (15 marks)
23. Describe the framework of the Indian power sector — its vertical structure, key institutions, regulatory bodies, legislative framework, and market segments. (12 marks)
24. Explain the Availability Based Tariff (ABT) mechanism in detail — its background, three components, UI rate vs frequency relationship, and a worked numerical example. What were its achievements and limitations? (15 marks)

Numerical Problems:

25. An NTPC station has an installed capacity of 2,000 MW and a NAPAF of 85%. The annual fixed cost is Rs. 600 crore. State X has a 15% share in the station. Calculate: (a) the annual capacity charge payable by State X, and (b) the monthly capacity charge per MW of normative generation.
26. In a 15-minute time block, a generator has a scheduled output of 300 MW but actually generates 280 MW (under-generation). The grid frequency during this block is 49.60 Hz, corresponding to a UI rate of Rs. 6.00/kWh. Calculate: (a) the UI energy quantity, (b) the UI payment, and (c) whether the generator pays or receives this amount.
27. A state utility has a contracted drawl of 500 MW from the central sector. On a particular day, its actual drawl varies as follows: 06:00-12:00: 550 MW; 12:00-18:00: 480 MW; 18:00-24:00: 600 MW. If the average UI rate for over-drawal periods is Rs. 5.50/kWh and under-drawal periods is Rs. 2.00/kWh, calculate the net UI settlement for the day.

MCQ / Objective Questions:

28. The property that most fundamentally distinguishes electricity from other commodities is: (a) Homogeneity (b) Non-storability and simultaneous production-consumption (c) Price volatility (d) Network effects
29. In ABT, the Capacity Charge is paid to: (a) recover variable fuel costs (b) recover fixed capital and O&M costs (c) penalise frequency deviations (d) fund transmission losses
30. The UI rate in ABT is highest when: (a) frequency is 50.2 Hz (b) frequency is exactly 50 Hz (c) frequency is below 49.5 Hz (d) the plant is on forced outage
31. The regulatory body responsible for ABT and inter-state open access in India is: (a) CEA (b) BEE (c) CERC (d) Ministry of Power
32. The Deviation Settlement Mechanism (DSM) was introduced for: (a) NTPC coal plants (b) Hydroelectric stations (c) Variable renewable energy (wind/solar) generators (d) Nuclear power plants
33. Which of the following is NOT a type of ancillary service: (a) Spinning Reserve (b) Reactive Power Support (c) Energy Charge (d) Black Start Capability
34. ABT was first implemented in India in: (a) Northern Region (1998) (b) Western Region (2000) (c) Southern Region (2001) (d) Eastern Region (2003)

NOTE: Answers to MCQs: 1-(b); 2-(b); 3-(c); 4-(c); 5-(c); 6-(c); 7-(b)