Indian Electricity Markets and their journey towards Integration - A Regulatory Perspective

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Why Electricity Markets?

When you introduce competition, generators compete to sell power.

This creates:

- Price discovery (what's power actually worth at different times?)
- Efficiency (low-cost generators run more)
- Investment signals (high prices attract new generation)
- Consumer choice (large buyers can shop around)

Evolution Timeline

Pre-2003: States had SEBs with complete monopolies. No private participation in distribution. Generation could be private but had to sell to SEBs. Massive inefficiencies, mounting losses.

2003 - Electricity Act:
Delicensed Generation
Created open access—large consumers could buy from anyone
Allowed trading as a licensed activity
Gave CERC mandate to promote competition in inter-state trading

2008 - Power Exchanges: IEX started operations in 2008, PXIL shortly after. These were organized markets where buyers and sellers could trade anonymously. Before this, all trading was bilateral (one-on-one contracts).

2020 - Real-Time Market: Took 12 years to add RTM! Why? Because you needed sophisticated systems, real-time communication, and participant readiness. RTM allows trading close to delivery time (1 hour ahead).

2026-onwards - Market Coupling: CERC had been discussing for a while. Going live now

Market Architecture Today

Power Exchanges:

- **IEX (Indian Energy Exchange) - largest, about 90%+ market share**
- **HPX (Hindustan Power Exchange) - newer entrant**
- **PXIL (Power Exchange of India Ltd.)**

Products traded:

DAM (Day-Ahead Market): Main product, trade for next day

RTM (Real-Time Market): Intra-day trading

TAM (Term-Ahead Market): Weekly, monthly contracts (less liquid)

G-DAM, G-TAM: Green products (renewable energy), introduced for RE compliance

Market Architecture Today

Participants:

- Generators (sell their power)
- DISCOMs (distribution companies buying for consumers)
- Traders (licensed intermediaries)
- Open access consumers (large industries buying directly)

Market size:

- Only about 5-6% of India's total electricity generation trades on exchanges.
- Rest is locked in long-term PPAs (Power Purchase Agreements).
- Low liquidity is a problem - thin markets can be volatile

How DAM works:

Timeline:

- Gate closure is 10:00 AM for power delivery the next day
- Participants submit bids by 10 AM
- Market clears by around 11:30 AM
- Results published, schedules coordinated with grid operators
- Power flows next day in 15-minute time blocks (96 blocks in 24 hours)

Bid structure:

- Sellers (generators) submit: "I'll sell X MW at price Y"
- Buyers submit: "I'll buy X MW at price Y"
- Can submit multiple price-quantity pairs

Auction mechanism:

- Double-sided sealed-bid auction
- Supply and demand curves constructed
- Where they intersect = Market Clearing Price (MCP)
- Usually uniform price auction (everyone pays same MCP)

How DAM Price Discovery Works

The Economics

Supply curve: Generators bid at their marginal costs. Cheapest first—maybe hydro at ₹1/kWh, then coal at ₹2-3/kWh, then gas at ₹4-5/kWh, expensive diesel at ₹8/kWh. You stack these to create upward-sloping supply curve.

Demand curve: Buyers bid their willingness to pay. Maybe a steel plant values power highly (bids ₹6/kWh), a DISCOM bids ₹4/kWh, etc. This creates downward-sloping demand curve.

Without congestion: Curves intersect at one point. Say ₹3.5/kWh for 50,000 MW. This is Market Clearing Price (MCP). Everyone who bid above ₹3.5 to buy gets power at ₹3.5. Everyone who bid below ₹3.5 to sell gets to sell at ₹3.5.

With congestion (transmission constraints): Now it gets complex. Say North region has cheap power but North-South transmission corridor is full. You can't move all that cheap power South. So:

- North clears at ₹2.5/kWh (surplus, cheaper)
- South clears at ₹4.0/kWh (deficit, expensive)
- These are Area Clearing Prices (ACP)

Real-Time Market (RTM)

Why RTM exists:
DAM closes at 10 AM for next day. But between 10 AM today and delivery tomorrow, things change:

- A generator trips unexpectedly
- Weather forecast was wrong, actual demand differs
- RE generation varies (wind dies down, clouds cover solar)

You need a mechanism to handle these deviations.

How RTM works:

Structure:

- 48 auction sessions per day
- Every half hour, there's an auction for delivery 1 hour later
- Example: 2:00 PM auction is for power delivery 3:00-3:30 PM

Gate closure: One hour before delivery. So much closer to real-time than DAM's day-ahead.

Participants: Same as DAM, but usage pattern differs. Entities use RTM for:
Balancing their position (bought too much/too little in DAM)
Responding to unexpected events
Arbitrage (if they think RTM price will be lower than deviation charges)

Link to deviation settlement: In India, if your actual drawal/injection differs from schedule, you pay deviation charges to grid operator. These can be expensive. Often it's cheaper to correct your position in RTM than to pay deviation charges.

Volumes: RTM is much smaller than DAM—maybe 10-15% of DAM volumes. It's meant for marginal adjustments, not primary procurement.

The Fragmentation Problem (or Is It?)

- Multiple exchanges operate independently
- IEX dominates: 89-99% market share (depending on segment)
- Price differences exist but volumes are tiny on non-IEX exchanges
- Question: Is this fragmentation or natural market consolidation?

What is Market Coupling?

- Integration of separate exchange platforms
- Single price discovery across all exchanges
- Implicit allocation of transmission capacity
- Used globally: Europe, US organized markets

Congestion Management

What is congestion?
Congestion occurs when you want to move more power on a transmission line or corridor than its capacity allows. It's a physical constraint.

Example:

- North region has 10,000 MW of cheap coal power available
- South region wants to buy it (their local generation is expensive)
- But North-South corridor capacity is only 7,000 MW
- Congestion: demand for transmission (10,000 MW) exceeds supply (7,000 MW)
- The price difference (₹1.5/kWh) reflects congestion value—the economic value of one additional MW of transmission capacity on that corridor.

India's zonal pricing model

India has 5 regions (zones):

Northern

Western

Southern

Eastern

North-Eastern

Each region gets one Area Clearing Price (ACP). All delivery points within a region pay the same price.

India's zonal pricing model

Why India uses zonal, not nodal:

1. **Complexity:** Nodal pricing requires real-time data from thousands of points, sophisticated metering, advanced market systems. Our infrastructure isn't there yet.

2. **Transition:** Moving from bilateral trading to zonal markets was big enough leap. Nodal would be overwhelming.

3. **Market readiness:** Participants need to understand and respond to nodal signals. That sophistication takes time.

4. **Regulatory capacity:** Nodal markets need constant oversight, dispute resolution at granular level. CERC would need massive expansion.

Future possibility: As systems mature, India might move toward more granular pricing. But for now, zonal is appropriate.

India's zonal pricing model

Congestion charges:

Price difference between zones = congestion charge.

Who pays: Buyers in deficit region pay higher ACP.

Who benefits: Sellers in surplus region get lower ACP but sell more volume.

Who gets the congestion rent: In theory, congestion rent (the price difference × MW transmitted) should go to transmission owners. In practice, this is complex and handled through various mechanisms including transmission charges.

Congestion Management

How congestion affects prices:

Without congestion (unconstrained): Power flows freely. One market clearing price everywhere. ₹3/kWh in North, ₹3/kWh in South, ₹3/kWh in East, West, Northeast.

With congestion: The algorithm creates price separation:

North (exporting region): ₹2.5/kWh - surplus region, low price

South (importing region): ₹4.0/kWh - deficit region, high price

The price difference (₹1.5/kWh) reflects congestion value—the economic value of one additional MW of transmission capacity on that corridor.

India vs. ERCOT - Key Differences

Difference 1 - Pricing Model:

India: Zonal pricing (5 zones, 5 prices when congested)
ERCOT: Nodal pricing (8,000+ nodes, thousands of unique prices)
Implication: ERCOT has perfect locational signals. A generator in West Texas sees different price than one in Houston. This drives efficient siting decisions. India's zonal model is cruder but operationally manageable.

Difference 2 - Market Maturity:
ERCOT: Operating since 1996, restructured in 2001. Two decades+ of market operation. Multiple boom-bust cycles, learned from failures (2011 crisis, 2021 winter storm). Mature participant base.
India: Exchanges only since 2008. Market coupling just implemented 2022-23. Still early learning stage. Many participants still figuring out optimal bidding strategies.

India vs. ERCOT - Key Differences

Difference 3 - Regulatory Structure:
ERCOT: PUCT (Public Utility Commission of Texas) sets policy. ERCOT as ISO manages markets and grid. Texas-specific regime, not federal FERC jurisdiction (unique in US). Relatively light-touch regulation, market-driven.
India: CERC for inter-state (central regulator), SERCs for intra-state (state regulators). Complex federal structure. Heavy regulatory oversight. POSOCO/NLDC as grid operator, exchanges as market platforms—separation of roles.

Difference 4 - Market Depth:
ERCOT: Substantial majority of power trades through markets—90%+. Competitive retail market, multiple retailers. Most generation is merchant (selling into market, not under long-term contracts).
India: ~5-6% on exchanges. Rest in long-term PPAs. DISCOMs are mostly monopoly retailers. Generation is mix of merchant and contracted.
Why this matters: Deep markets have better price discovery, more liquidity, lower volatility. Thin markets can be manipulated, prices swing wildly.

India vs. ERCOT - Key Differences

Difference 5 - Ancillary Services:

ERCOT: Comprehensive AS markets:
Regulation up/down (fast frequency response)
Responsive reserves (spinning, non-spinning)
Non-spinning reserves
Black start capability
Voltage support
Each service has separate market, separate prices, competitive procurement.

India: Limited AS market. RRAS (Reserve Regulation Ancillary Services) launched but narrow scope. Most frequency regulation through regulatory means (IEGC compliance, deviation settlement mechanism). Reserves often mandated, not market-procured.

India vs. ERCOT - Key Differences

Difference 6 - Market Design Philosophy:
ERCOT: Energy-only market. No capacity payments. Price spikes during scarcity are feature, not bug—they signal need for new generation investment. Prices can hit $5,000/MWh or higher during shortages.
India: Hybrid approach. Capacity payments exist through various mechanisms (capacity charges in PPAs, availability-based tariffs). Price caps on exchanges prevent extreme spikes. Philosophy: reliability through contracts and regulation, markets for marginal optimization.

Difference 7 - RE Integration:

ERCOT: Texas leads US in wind power. ERCOT has sophisticated RE forecasting, negative pricing to manage surplus, market mechanisms for flexibility.
India: Rapidly adding RE but struggling with integration. Must-run status for RE creates market distortions. Forecasting improving but not yet sophisticated. Curtailment issues in high-RE states.

Ancillary Services in India

What are ancillary services?
AS are services necessary to support reliable transmission and delivery of electricity, beyond just energy supply. They keep the grid stable.

Categories:
1. Frequency regulation: Grid frequency should be 50 Hz. When load exceeds generation, frequency drops. When generation exceeds load, frequency rises. Regulation services inject/absorb power to maintain frequency.
Fast response: Responds in seconds (automatic generation control)
Slow response: Responds in minutes (manual dispatch)
2. Reserves: Backup capacity ready to come online quickly if a generator trips or load spikes.
Spinning reserves: Already synchronized, can deliver in seconds
Non-spinning reserves: Can start and deliver in 10-30 minutes
Replacement reserves: Longer timeframe, 30+ minutes
3. Voltage support: Maintain voltage within acceptable range. Requires reactive power injection/absorption. Usually provided by generators, synchronous condensers, or FACTS devices.
4. Black start: Capability to restart grid after complete blackout without external power source. Hydro and some gas units have this capability.

Operational Challenges

1 - Limited market depth (PPA dominance):

Problem: 94% of power is in long-term PPAs. Only 5-6% trades on exchanges.
Why this matters:
Thin markets are volatile—small demand/supply shifts cause big price swings
Price discovery is poor with limited participation
Market power concerns—a few large players can influence thin markets
Limited commercial opportunities for new flexibility providers

Root causes:

DISCOMs have must-serve obligation; they contract long-term for certainty
Regulatory push for power procurement through competitive bidding (PPAs)
Risk aversion—DISCOMs prefer locked-in prices over market exposure
Banking restrictions—DISCOMs can't take market risk without regulatory approval

Electricity Derivatives

- Supreme Court resolved SEBI-CERC dispute (October 2021)
- MCX and NSE received SEBI approval (June 2025)
- Trading launched July 2025
- Framework: CERC regulates physical delivery contracts, SEBI regulates financial derivatives

Market coupling: Shadow pilot completed, DAM implementation Jan 2026

IEX's legal challenge at APTEL ongoing

Electricity derivatives operational (June-July 2025)
Green market products expanding
Intra-day trading, capacity markets, storage frameworks in discussion

India's zonal pricing model

Takeaway 1 - Markets bring efficiency but need robust regulation

Takeaway 2 - Market coupling is transformative for India

Takeaway 3 - Operational challenges remain significant

Takeaway 4 - Legal framework continues to evolve

Takeaway 5 - India's path is unique - copying models?

Thank You!