ELECTRICITY EMPLOYEES' FEDERATION OF INDIA (EEFI)

GENERAL COUNCIL MEETING
October 3rd - 4th 2026
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GS Report, Part II

Industry

This Industry Report is placed before the General Council of EEFI meeting at Kolkata on 3 and 4 October 2026. It covers major developments in India's power sector from the 10th National Conference to the end of September 2026, and is meant to assist the Council in fixing the Federation's line for the period ahead.

The analytical frame of this report is framed in that line – to understand the new Power ecosystem under the new policy regime. Electricity is rapidly turning from an essential public service to a speculative commodity. Installed megawatts are now not the same as dependable, affordable supply at the hour and place of need. Private capital is entering the most profitable slices of the system — urban feeders, data-centre parks, virtual contracts, nuclear licences — while public utilities retain universal service, rural and agricultural supply, grid discipline and political accountability. That is the political economy of the period.

1. Basis of the figures

Capacity and demand figures are taken from CEA monthly installed-capacity statements, Load Generation Balance Reports and contemporaneous Grid-India / Ministry of Power records, read with CERC regulations and court orders. Where monthly CEA statements differ by a few hundred megawatts, the latest consistent all-India snapshot — 31 August 2026 — is used, and earlier months are treated as what they were: snapshots of that date.

2. The central argument of the period

India crossed 500 GW of installed capacity and, by 31 August 2026, stood at about 555.82 GW. Non-fossil sources — solar, wind, large hydro, other RE and nuclear — accounted for about 304.33 GW, or 54.75 per cent, overtaking fossil nameplate capacity. Solar alone reached about 168 GW. On paper this is a historic energy-transition milestone, five years ahead of the 2030 NDC target of 50 per cent non-fossil capacity.

The summers and the weak monsoon of 2026 showed the other side of the same coin. Peak demand hit 256.1 GW on 25 April and an all-time high of 270.8 GW on 21 May. It returned to 269 GW on 10 September — an almost summer-like peak in a month that normally eases. Night-time shortages reached about 5.4 GW in the first heatwave and as much as 7.7 GW in September. Exchange prices hit the High Price Day-Ahead ceiling of Rs 20 a unit. Several States imposed rotational cuts. The Ministry invoked Section 11 not only for imported-coal and gas plants but, in late September, for captive stations of 50 MW and above.

The problem was not a shortage of nameplate megawatts. There was a shortage of firm, dispatchable and affordable electricity after sunset, when solar fell away and cooling and irrigation load remained. That is the difference between installed capacity and dependable capacity. Without storage, flexible hydro, flexible thermal and disciplined long-term contracting, further solar addition will deepen the evening ramp, not close it.

At the same time the legal and market architecture is being rewritten: parallel licensing on shared public networks, cost-reflective tariffs and a five-year phase-down of industrial and railway cross-subsidy, market coupling and capacity markets, VPPAs and electricity futures, DISCOM & TRANSCO IPOs, TBCBs in Intra-State Grids and the opening of civil nuclear power to private groups under the SHANTI Act. The 2026 scarcity is therefore not only an operational event. It is the first stress test of a reform model that treats electricity as a market commodity while leaving social obligation with the public DISCOM. EEFI was pointing out this from the very beginning – transition should be

planned with Public Utilities, developing storages and matching the demand of our country in Peak period.

3. Installed capacity and the changing mix

3.1 All-India snapshot as on 31 August 2026

The following table is the all-India portfolio as on 31 August 2026. It is consistent with the CEA statements for June and July 2026 (total 548.9 GW on 30 June; about 552 GW on 31 July).

Source	Installed capacity (GW)	Share
Coal	224.16	40.33%
Solar	168.04	30.23%
Wind	58.52	10.53%
Large hydro	52.06	9.37%
Gas	20.12	3.62%
Biomass / cogeneration	10.87	1.96%
Nuclear	8.78	1.58%
Lignite	6.62	1.19%
Small hydro	5.18	0.93%
Waste-to-energy / other RE	0.88	0.16%
Diesel	0.59	0.11%
Total	**555.82**	**100%**

As on 31 August 2026, aligned with CEA monthly installed-capacity statements.

Fossil capacity remained about 251.49 GW (45.25 per cent). Non-fossil capacity was about 304.33 GW (54.75 per cent). Renewable energy excluding large hydro was about 243.49 GW. Coal is still the single largest source. Solar is now the second, but growing rapidly.

3.2 Ownership of the new capacity

The ownership split behind these totals is as important as the fuel split. CEA sector tables through mid-2026 show the private sector holding the bulk of incremental renewable capacity, while the State sector continues to carry a large share of thermal, hydro and the entire public distribution obligation. Nuclear remains almost entirely in the Central public sector — NPCIL, BHAVINI, NTPC partnerships still now — though the SHANTI Act has just opened private entry in the sector.

A substantial share of the capacity added after the 500 GW milestone is therefore private solar and wind. Public utilities and State DISCOMs continue to bear grid stability, rural electrification, subsidised supply and social-welfare obligations. Profits concentrate where contracts and certificates can be sold; risks concentrate where the universal-service duty remains.

3.3 How the mix looked earlier in the period

In April 2026 the official snapshot was about 537.3 GW (53.6 per cent non-fossil; solar 154.2 GW). India had already crossed 50 per cent non-fossil capacity on 30 June 2025 (484.82 GW total; 242.78 GW non-fossil) — five years ahead of the NDC date. The jump from that 485 GW / 50 per cent moment to 556 GW / 55 per cent in fourteen months is almost entirely renewable nameplate, overwhelmingly solar.

4. Demand, scarcity and the 2026 operating crisis

4.1 Two summers, two stories

2025 and 2026 must be read together. The IEA had projected only about 4 per cent demand growth for 2025 after a cooler first half and an early monsoon. Renewables displaced coal in May 2025; RE's share of generation rose to about 17 per cent from 13–14 per cent a year earlier; coal plant load factors fell. That year looked, briefly, like a success story of green displacement.

2026 reversed the weather and exposed the structure. Severe heat, industrial growth, rising electrification and a weak southwest monsoon along with an El Nino (seasonal rainfall

about 15 per cent below normal by early September) drove cooling and irrigation together. Coal remained the backbone at the afternoon peak — about 67 per cent of generation on the 25 April 256.1 GW day, with solar contributing about 21.5 per cent. Fortunately, the national grid did not collapse. That fact is real, and it is not the whole story.

4.2 Peak demand through the year

Date / period	Peak / shortage	What it showed
25 April 2026, 15:38 hrs	256.1 GW peak	First all-time high of the year; coal ~67%, solar ~21.5% at peak
21 May 2026, ~15:45 hrs	270.8 GW peak	Highest demand ever met; 46.7 GW added between 08:00 and 15:45
April–June 2026	Peak +~12% YoY	Heat + cooling + industry; Section 11 on imported-coal and gas stations
Evening / night, summer	~5.4 GW night deficit	Solar drop after sunset; cooling load stays
Late June 2026	264.8 GW (Sat)	Demand stayed above 250 GW as monsoon lagged
10 September 2026	269 GW peak	Near-summer peak in a month that normally eases
First week of September	>20 MU daily energy deficit	Vs <1 MU in the comparable week of 2025
27 August 2026	>10 MU national energy deficit	Coal stocks, hydro slump, thermal outages
September nights	Shortage up to 7.7 GW	Above April–May night shortages; hydro −12% YoY

Figures from CEA / Grid-India and Ministry records. CEA LGBR 2026-27 had projected an all-India peak around 272 GW for the year; actual May already touched 270.8 GW.

4.3 The duck curve has become the operating fact

An Economic Advisory Council to the Prime Minister (EAC-PM) working paper on the net load of the Indian grid (July 2026) put numbers on what operators already knew. On 21 May the system took on 46.7 GW between 8 a.m. and mid-afternoon — more than the entire British peak. Across comparable summers the evening climb roughly doubled in three years, from about

36 GW in May 2023 to about 74 GW in May 2026. The morning ramp-down as solar floods nearly tripled, from 18 GW to 53 GW. The midday "belly" of conventional net load stayed pinned near 150 GW because extra daytime demand was met almost entirely by new solar. The system is therefore not short of electrons at noon. It is short of ramp and firm energy after 6 p.m. Certainly, a profit driven private controlled energy market can't resolve this issue in a favourable way to the people.

4.4 State-wise experience

National "demand met" hid State-level rationing.

1. **Kerala.** Normal monsoon peak of 3,600–3,700 MW crossed 5,000 MW. Average deficit approached 900 MW. On 11 September availability was about 4,200 MW against expected demand of about 5,100 MW. Daily cuts of 30–60 minutes were imposed.
2. **Tamil Nadu.** Load-shedding plus distress purchase. The State Electricity Minister stated that TNPDCL was buying at about Rs 20/unit; earlier peak purchases had crossed Rs 22/unit.
3. **Manipur.** Rotational cuts in September. About 180 MW available against peak demand of about 270 MW — a 90 MW hole. Causes cited: lower hydro, coal shortage, thin market.
4. **Karnataka.** Peak of 20,094 MW on 11 September against a previous peak of 18,655 MW in March. Weak monsoon, low reservoirs, inadequate storage against solar, high cooling load.

These four sample cases are not anomalies. They are what a solar-heavy, storage-light, short-term-market-dependent system looks like when weather turns against hydro and wind at the same time as demand spikes.

4.5 The short-term market under scarcity

What solution does this market system provide in this situation? Purchasing the deficit amount from Real-Time-Market. But there arises the most dangerous turn in the whole story! In normal weeks, competition among generators can discipline prices. In a shortage, the story changes; sell bids shrink and purchase bids rise. Deficit DISCOMs bid against each other for the same scarce blocks. Bargaining power shifts to sellers. The ordinary Day-Ahead Market has a Rs 10/unit cap; the High Price Day-Ahead Market allowed prices to reach the Rs 20/unit ceiling, which was hit in September several times. When States buy at Rs 20–30/unit and simultaneously cut supply to households, the question is no longer "market efficiency". It is the bankruptcy of the consumer protection under the Electricity Act, 2003 exposed.

Section 11 directions — first to imported-coal and gas stations in the summer, then on 27 September 2026 to captive coal stations of 50 MW and above for October–December, requiring surplus to be offered on exchanges — are an official admission that the market, left alone, has already failed to deliver the public-interest quantity of power.

4.6 Coal logistics and hydro

This crisis is structurally different from the coal-stock crises of earlier years, but coal logistics still mattered. Mid-September thermal stocks were about 7–9 days — a three-year low. On 19 September, 74 of 190 monitored plants were marked critical; rail-fed plants held only about a third of normative stock. Hydro generation was down about 14 per cent year-on-year in July and about 12 per cent in the first three weeks of September — a fifth consecutive monthly decline. Coal generation rose about 18 per cent in September to fill the gap. BCCL's Q1 FY 2026-27 incentive scheme (relaxation of performance-incentive charges and cash discounts up to 10 per cent on additional lifting) was one of such

official responses. It does not substitute for a planned, power-first fuel and rake system across Coal, Railways and Power.

5. Resource adequacy: nameplate MW is not firm MW

The generation sector, historically built by Central and State public utilities, has moved towards private ownership especially in solar, wind, merchant thermal and storage. Transmission, distribution, system operation, universal service and strategic fuel security remain, in substance, public responsibilities; whereas the renewables, power markets and high-revenue industrial consumers are being increasingly controlled by the private players. This 2026 showed that private installed capacity cannot be claimed as any mark of progress for satisfying the need of stable power demand.

Capacity planning has to shift from nameplate addition to dependable MW in the evening, at night and in monsoon-failure weeks. That means battery energy storage, pumped storage, flexible hydro, flexible thermal, demand response, strategic reserves, long-term PPAs and fuel security in a planned way, by Public utilities — not any more rat-race for solar installations.

CERC's staff paper on a capacity market (three designs: resource-adequacy obligation, reserve capacity, and a secondary short-term market for existing plant) is the market-side recognition and solution of the same problem. A capacity market that socialises the cost of private peakers onto DISCOMs and consumers, without restoring public planning of firm capacity, will not solve the problem the 2026 evening peak revealed. It will price it.

6. The legal-political offensive: Bill, Policy, parallel licence

6.1 Draft Electricity (Amendment) Bill, 2025

The draft Bill, placed for comments in October 2025 and still in consultation through 2026 (Lok Sabha reply of 29 January 2026), is the principal legislative instrument for imposing final round of reform to India's power sector. Its main structural

proposals, as they stood in the draft and the Ministry's explanatory notes, are:

1. Multiple distribution licensees in the same area, using the existing DISCOM network on regulated wheeling charges — i.e. parallel licensing without a second wire.
2. Mandatory cost-reflective tariffs; SERCs empowered to determine tariffs suo motu from 1 April each year if utilities delay filing.
3. Elimination of cross-subsidy for manufacturing, Railways and metro within five years; State subsidy under Section 65 to continue "transparently".
4. SERCs, in consultation with the State government, may exempt DISCOMs from the obligation to supply consumers whose maximum demand exceeds 1 MW.
5. An Electricity Council chaired by the Union Power Minister; a separate Electric Line Authority for transmission right-of-way.
6. Deeper open access, power-market and derivative mechanisms, central standard-setting on RPO/RCO and cybersecurity.

The Bill is designed to allow a private licensee to use a public network built over decades at his choice, pick high-revenue urban and industrial load, and leave agricultural, rural and subsidised consumers with the residual public DISCOM. EEFI along with other Employee federations, officers' associations, State utilities, farmers' organisations and NCCOEEE announced protest programmes and strike actions when introduction in Parliament was mooted. We must keep in mind that, this Government during this interim period, has notified the SHANTI Act, New Labour Codes and VB-GRAM-G withdrawing MGNREGA.

As of September 2026 the Electricity (Amendment) Bill had not been enacted. Consultation was extended more than once. That delay is itself a product of resistance. But it is not a withdrawal of the project.

6.2 Draft National Electricity Policy 2026

On 22 September 2026, the Draft NEP has been published. The Draft NEP 2026 is intended to replace the 2005 Policy. It attempts to present itself as the map to 24×7 quality power for Viksit Bharat at 2047. Its first political act is itself shamelessly narrated. Access and scarcity problem, it says, are solved. What remains is DISCOM finance, industrial tariffs, and a green transition that private capital and markets will deliver. That is why the draft pushes cost-reflective tariffs, exemption from Universal Service Obligation for large consumers, surcharge-free open access for manufacturing, capacity markets, competitive bidding inside the States, listing and PPP in distribution in accordance with the NMP 2.0, private nuclear power, and public money to de-risk private finance.

Those founding claims have to be denounced and rejected first. Official definitions inflate access. Peak supply, evening supply and fuel-backed supply are still scarce. Private ownership of about half the capacity did not end shortage. It paved a path to capture more profit rent when shortage appears.

The TRUTH is that - Access has not been universally achieved

Village electrification is not household electrification. Since 2004 a village is declared electrified if there is a distribution transformer and lines in the inhabited area, electricity in specified public places, and at least 10 per cent of households connected. All inhabited census villages were declared electrified by 28 April 2018 on that definition. That is infrastructure on paper. It is not a wired, usable connection in every home.

Saubhagya scheme covered so-called “willing” households. Anyone who does not apply is counted as unwilling. After the scheme closed on 31 March 2022, ordinary Supply Codes apply: identity and occupancy proof, a licensed-contractor test report in most States, internal wiring beyond the single light point Saubhagya itself provided, and payment for poles and conductor beyond a short free service-line (commonly 30–40 metres; for

agriculture often 500 metres). Distance and poverty are written down as lack of willingness.

CAG Report 17 of 2025 found that "100 per cent coverage" by March 2019 was declared after the target was revised down. Actual Saubhagya connections by March 2019 were about 151.60 lakh — under 58 per cent of the original 300-lakh target. The target itself was fixed by excluding more than 200 lakh houses from an original estimate of 517 lakhs. RDSS has since sanctioned grid works for another 13.65 lakh PVTG, tribal, Scheduled Caste and border households even after declaring the 100 per cent electrification target achieved. NFHS-5 put household electricity at 96.8 per cent, not 100. The draft's claim that access is achieved 100% is certainly not true.

Scarcity has not been solved

CEA's Load Generation Balance Report (LGBR) 2026-27 still projects a Southern peak deficit of about 9.6 per cent (8.1 GW) and an Eastern peak deficit of about 16.2 per cent (6.0 GW), next to a thin all-India surplus on paper. In April–May 2026 the grid fell short on 36 of 61 days at the non-solar-hour peak, and on 6 of 61 days even in solar hours. After hydro fell 12–14 per cent, September night shortfalls reached about 7.7 GW. In the first 20 days of September the day-ahead average rose from about Rs 3.42 to Rs 7.77 per kWh year on year; from 6 p.m. to 11 p.m. the clearing price sat on the Rs 10 ceiling. On stressed evenings purchase bids ran to about 1,03,450 MWh against sell bids of about 2,418 MWh. HP-DAM averaged about Rs 19.6 a unit in April 2026. Mid-September thermal stocks were about 7–9 days — a three-year low. On 19 September, 74 of 190 monitored plants were marked critical. Mine-head inventories can look comfortable while stocks at the plant gate collapse. That is three ministries chasing three commercial targets, not a planned power-first fuel and rake system.

Private generation is not proof of success

As on 31 March 2026 the official split was Central 23.3 per cent, State 24.4 per cent and Private 52.3 per cent (2,78,632 MW out of 5,32,740 MW). Private plants run when the PPA or the

exchange pays. They have no social duty to dispatch. Capacity payments, HP-DAM and a Rs 10 ceiling with an escape hatch for high-cost plant turn scarcity into revenue. Capacity rose. Evening scarcity, coal failure at the plant gate, and exchange prices at or above the cap remain. Deepening that market is not public adequacy.

What the draft then proposes

- Per-capita targets of 2,000 kWh by 2030 and 4,000-plus by 2047, without a public provision model — a dual system in which those who can contract buy for themselves.
- Full cost-reflective tariffs from 2026-27; no new regulatory assets; automatic indexation if no tariff order is issued; monthly pass-through of purchase-cost increases; more fixed-cost recovery through demand charges; a cross-subsidy floor at 50 per cent of ACS; subsidy only if paid in advance under Section 65.
- Regulators may exempt DISCOMs from USO for consumers of 1 MW and above. Manufacturing, Railways and Metro to be freed of cross-subsidy and additional surcharge.
- VPPAs, RCO with buyout, discouragement of net metering above 5 kW, storage in place of banking, hybrid RE, peer-to-peer trading and aggregators — complete intrusion of speculation in power eco-system and further development of green capacity whose preferred owner is private and industrial capital.
- Coal as flexible baseload serving a market-dominated RE build-out; gas peaking with capacity markets; 100 GW nuclear by 2047 with private collaboration on modular and Bharat Small Reactors.
- Phased capacity markets; routing of long-term PPA energy through exchanges; forwards and hedging; one-way declining path for open-access surcharge; an India Energy Stack.
- Competitive bidding as the default inside the State as well as between States; planning without prior agreement of beneficiaries; dedicated green feeders for those who can

contract 100 per cent RE; unbundling of STU, SLDC and transmission service provider tied to intra-State bidding.

- Multiple licensees, PPP and listing of DISCOMs; shared wires; prepaid meters first for government then industry and commerce; a distribution system operator for distributed resources and aggregators.
- Finance of about Rs 50 lakh crore by 2032 and Rs 200 lakh crore by 2047, met not by public ownership of the new assets but by stable private revenue, NaBFID/NIIF platforms, first-loss and multilateral guarantees and a climate-finance taxonomy.

As a whole the draft does four things that are one in design. It introduces mechanisms so that leftover access and evening scarcity become a DISCOM-discipline problem. It completes the unfinished business of 2003 in supply — intra-State transmission, the distribution wire, bulk storage and nuclear. It socialises risk and privatises return. It treats electricity as a commodity, so that the purchasing capacity determines the right to electricity.

EEFI strongly reiterates that, this model is bound to fail again and it is going to be the last nail over the public power utilities. A public-infrastructure alternative is not obscure; we demand: publicly owned investment in RE, storage, intra-State grids and nuclear; USO for every consumer with no 1 MW exit that does not compensate the common pool; distribution as a publicly owned service; planning that sets the mix rather than destabilising it; public banks funding public assets; agri-feeder solarisation by public utilities as a programme for farmers; coal–rail–power as a planned chain; access defined as a wired, affordable, adequate household connection. The draft does take the opposite path.

6.3 Parallel licensing on the ground

While the new Amendment Act remains pending, the attack of parallel licensing has increased dangerously. Section 14 of the 2003 Act already permits more than one distribution licensee in an area. What is new is the attempt to drop the requirement of a separate network and allow the new licensee to ride the existing

DISCOM system. We must recall that EEFI is the first organisation that could successfully understand the link between the private sector smart metering and the parallel licensing and opposed the first. Now, applications of parallel licensing in 2025–26 show a clear pattern: private capital targets commercially dense districts and they are already sure that the required infrastructure has been established and the Bill is going to be passed.

Karnataka — a working-class victory

In May 2026 Tata Power applied to KERC for parallel licences covering 19 districts under all five ESCOMs — more than half of the ESCOMs' total sales. BESCOM and the other ESCOMs objected to statutory non-compliance, network readiness, consumer protection and cherry-picking. The State Cabinet directed ESCOMs to file individual objections. Employee unions, engineers, farmers and consumers organised; KERC was reported to have received close to 20 lakh objections. On 3 July 2026 Tata Power withdrew the application at the hearing. EEFI recorded it as a historic victory of electricity employees, engineers, farmers and the people. It is a victory. It is not a settlement of the legal framework that made the application possible.

Maharashtra, Haryana, Goa, Puducherry

Maharashtra. Torrent Power, Adani Electricity and Tata Power sought entry into Pune, Thane–Palghar, Nashik, Chhatrapati Sambhajinagar, Nagpur, Navi Mumbai–Panvel and Mumbai-suburban pockets. Torrent

tabled a ₹3,110 crore Nagpur plan (underground cabling, smart meters, 5–7 per cent tariff discount). Adani Electricity Navi Mumbai proposed about ₹5,700 crore. MERC hearings split industrialists from MSEDCL, unions and researchers. MSEDCL has also appointed eight bankers for a proposed IPO of ₹8,000–10,000 crore — the first attempted IPO of a fully State-owned DISCOM.

Haryana. Eleven Power sought a parallel licence for Gurugram and Nuh. DHBVN told the Commission that the

two districts generate more than 42 per cent of its revenue and that the existing network represents an investment of about ₹11,398 crore, against a much thinner private proposal. HERC examined financial and operational capacity and cherry-picking. In September 2026 EEFI asked HERC to reject the petition (No. 30 of 2026) after the expert committee's own findings. A parallel fight continues against an Agriculture DISCOM and prepaid smart meters.

Puducherry. Adani Energy Solutions incorporated Adani Electricity Puducherry Limited on 26 August 2025 — a corporate vehicle prepared for the announced privatisation of distribution in Union Territories. After long fight, the Chennai HC has ruled out the scope of privatisation.

Goa and other UTs. The same UT-privatisation template remains on the table.

Data-centre parks as a second door

Parallel licensing is not only geographic. It is being structured around single high-value clusters; and data centres are the new players in industrial market. India's operational data-centre load grew from about 375 MW in 2020 to around 1,575 MW in 2026. The Ministry of Power told Parliament in July 2026 that AI data centres could add 26.3 GW of load by 2031-32 — nearly double the 13.56 GW estimate given in March. About 17 GW of connectivity applications were already with State transmission utilities. Peak demand is now officially projected at 289 GW in 2026-27 and 388 GW by 2031-32.

Adani Energy Solutions Step-Eleven Ltd. has applied to UPERC for a distribution licence specifically for the Data Centre Park of DC Development Noida Ltd. in Sector 62, Noida. There is already a 2023 precedent: NIDP Developers received a licence for a designated park at Knowledge Park-V, Greater Noida, under the UP Data Centre Policy. A private distributor can therefore attach itself to a concentrated, 24×7, high-paying load without taking any rural or agricultural obligation. If those loads leave the public DISCOM, the cross-subsidy arithmetic that supports farmers and poor households breaks. And secure stable electricity will be swallowed by these data centres.

6.4 DISCOM finances, ranking and the capital-market route

The draft NEP treats distribution as the leftover failure of 2003 — losses, tariffs that do not cover cost, monopoly – everything is portrayed as inefficiency about the public DISCOMs. Certainly, AT&C losses and theft exist. But, they are not the main fiscal engine. Power purchase is 70–80 per cent of DISCOM cost. National average procurement was about Rs 5.38/kWh in 2024-25; actuals were near Rs 5.7 in 2022-23 when imported coal and short-term prices spiked. Late Payment Surcharge rules improved generator cash: DISCOM dues to GENCOs fell from about Rs 1.40 lakh crore in 2022 to about Rs 4,927 crore by January 2026. That is a shift of liquidity toward generation. It is not proof that purchase prices fell.

The 2003 claim that the Electricity Act will resolve all financial issues have proved to have failed in the last 23 years. The accumulated DISCOM losses in 2003 was Rs 26,000 crore; that stands around Rs 6.47–6.90 lakh crore now. Outstanding debt as on 31 March 2025 was Rs 7.26 lakh crore. FY25 profit after tax of the whole distribution sector was Rs 2,701 crore only because private DISCOM profit of Rs 12,138 crore offset State DISCOM losses of about Rs 9,437 crore. Regulatory assets are about Rs 1.74–3 lakh crore, concentrated in Tamil Nadu, Uttar Pradesh and Rajasthan; Delhi alone holds about Rs 38,500 crore. State tariff subsidy is of the order of Rs 2.6 lakh crore (2025). These are despite the fact that AT&C losses have come

down from about 22 per cent to 15–16 per cent in the last one decade; the ACS–ARR gap on accrual after subsidy is a few paise.

Each superficial clean-up — the 2001 dues scheme, FRP 2012, UDAY 2015, Atmanirbhar 2020, RDSS 2021 — has been followed by rebuilt debt and regulatory assets. UDAY put DISCOM debt on State budgets. The debt came back. The Governments at Centre never tried to resolve the issues of the DISCOMs. Painting the public DISCOM as permanently broken, and then offering PPP, listing and multiple licensees as the cure, is the same prescription the draft now tightens now and the Act introduced in 2003.

The Ministry–REC's Distribution Utilities Ranking for FY 2023-24 scores DISCOMs on financials, smart-meter penetration, RPO, demand response and resource-adequacy contracting — a scorecard aligned with RDSS and cost-reflective tariff doctrine, not with universal-service duty; it is to make public listing lucrative. MSEDCL's IPO mandate (eight bankers; ₹8,000–10,000 crore) is the most advanced listing case. Assam, Bihar and West Bengal have started similar processes. Listing a DISCOM does not resolve problems. It opens up the way towards disinvestment and then privatisation.

7. Markets, instruments and the financialisation of electricity

7.1 Market coupling

CERC's Power Market (Second Amendment) draft of 17 April 2026, following the 23 July 2025 suo motu order, proposes coupling of exchange bids under a Market Coupling Operator so that one clearing price emerges — the official slogan is "One Nation, One Grid, One Price". Grid-India is designated MCO. IEX, which holds around 85 per cent of DAM/RTM volume, challenged the July 2025 order. APTEL on 13 February 2026 held that coupling could not proceed without a proper regulatory framework and IEX consent. IEX carried the matter to the Supreme Court (Civil Appeal No. 7054 of 2026). On 27 July 2026 the Court declined an interim stay. CERC told the Court that norms would be issued shortly and spoke of a four-to-six-week window. Grid-India has separately flagged software robustness, single-point-of-failure, settlement and cost allocation. Implementation is therefore contested, not completed. It will create a single market entity and opaque price fixation mechanism – those who control market will control the power sector.

For DISCOMs the practical loss is the ability to shop across three exchanges for the cheaper block. Coupling plus the still-pending Market-Based Economic Dispatch architecture would shift operational control from State utilities and State Gencos toward a central algorithm. Electricity is a concurrent subject. That shift

is a federal question, not only a market-design question. Claimed welfare gains from pilots have been marginal. Additional MCO, algorithm and settlement costs will be socialised onto procurement costs.

7.2 Virtual Power Purchase Agreements

CERC's VPPA framework is another blow in this situation. A Virtual Power Purchase Agreement (VPPA) is a financial contract between a renewable energy developer and a corporate buyer. The project sells electricity to the wholesale market, while the buyer does not physically receive the power. Instead, the two parties settle the difference between the market price and a pre-agreed strike price: the buyer pays if the market price is lower, and the developer pays if it is higher.

The project's Renewable Energy Certificates (RECs) or other environmental attributes are transferred to the buyer, enabling it to claim renewable energy use in sustainability reports even if its actual electricity comes from fossil-fuel-heavy grids. Thus, VPPAs are essentially financial swaps with certificate transfers, allowing large corporations, particularly big tech and multinational companies, to claim "green energy" credentials without directly purchasing clean power or changing their actual consumption. They do little for local communities or small renewable projects and instead strengthen the role of large developers and financial entities.

7.3 Shorter RTM, capacity market, GNA charges, electricity futures

- CERC's RTM discussion paper would cut the bidding window from 15 minutes to 5 minutes and shrink the gap from schedule revision to delivery from 75 minutes to 50 minutes. Faster markets reduce some forecast error; they also thicken the speculative layer of intra-day trading. It is a mechanism to introduce higher degree of speculation and derivative trading in the power market.
- The capacity-market staff paper proposes a new payment stream for the "availability" of power

capacity, in addition to payments from the existing energy market. It is the payment over capacity not the energy!

- A graded compensation charge is proposed for renewable-energy developers who fail to meet GNA milestones such as land acquisition, financial closure or commissioning. Instead of automatically losing their grid connectivity and having their bank guarantees encashed, developers could retain connectivity by paying the prescribed compensation charge – further Ease of Doing Business for private players.
- The National Stock Exchange (NSE) has launched monthly electricity futures contracts, potentially making the power market increasingly speculative. The contracts provide price discovery and hedging tools for generators, distribution companies and large consumers. On the first day, over 4,000 contracts were traded, representing around 200 million units of electricity, with a turnover of over Rs 870 million. The contracts are based on Indian Energy Exchange (IEX) prices and settled in cash.

7.4 Supreme Court on Railways and on regulatory assets

On 8 May 2026 the Supreme Court (Civil Appeal No. 4652 of 2024 and connected matters) upheld APTEL and held that Indian Railways is not a deemed distribution licensee. It is a consumer. It must pay Cross-Subsidy Surcharge and Additional Surcharge on open-access power like any other consumer. Operation of traction wires does not make a deemed licensee. The judgment protects a slice of DISCOM revenue that Railways had sought to escape.

A Supreme Court direction (6 August 2025) requiring DISCOMs to clear regulatory assets within a few years, along with "Change in Law" rulings (23 May 2025) allowing developers to recover accumulated carrying costs, works in the opposite direction: past losses and project risks are added to future electricity tariffs.

Corporate generators are protected, while households ultimately bear the cost.

8. Other Central regulations and administrative changes

8.1 Storage under the tariff framework and Grid Code

CERC's Tariff (Second Amendment) Regulations 2026 bring Battery Energy Storage Systems (BESS) and pumped storage under the national tariff framework, covering Return on Equity (RoE), capacity charges and payment security. Public utilities, already facing financial stress, are being pushed to support costly storage systems so that private renewable energy (RE) can be absorbed into the grid.

The Draft Grid Code changes propose a general minimum trial capacity of 50 MW for standalone Energy Storage Systems (ESS), with instalment provisions for projects above 250 MW. They also provide for congestion charges when power flows exceed the grid's transfer capacity and restrict grid access for entities that default on statutory charges.

The Draft Electricity (Amendment) Rules 2025 treat ESS as a separate element that can be owned, leased or rented by Gencos, Transcos, DISCOMs, consumers, SLDCs or independent storage companies. CEA's draft Safety amendment adds a new Chapter X-A covering BESS safety requirements, including fire protection, ventilation, adequate spacing and third-party fire audits.

8.2 Consumer rules, meters, RCO

Draft Electricity (Rights of Consumers) Amendment Rules 2026: Introduce demand response and tighter connection timelines - 3 days in metros, 7 days in municipalities, 15 days in rural areas and 30 days in hilly rural areas. We must see it as a response to our struggle against ghost billing due to smart meters also. The Rule says, abnormal bills must be resolved within 30 days, without disconnection if the consumer pays the average amount. At the same time, it says, Time-of-Day (ToD) tariffs

will apply to Commercial & Industrial (C&I) consumers above 10 kW from 1 April 2027.

Draft CEA Metering Amendment 2026: This is complementary to the previous one; it establishes the requirement of smart meters wherever a communication network exists, prepaid functionality through AMI, and prepayment meters elsewhere with SERC approval. It also specifies accuracy classes for low-voltage open-access interface meters.

Revised RCO draft under the Energy Conservation Act: Raises the consumption-side Renewable Consumption Obligation from 29.91% in 2024-25 to 43.33% in 2029-30, covering wind, hydro, distributed RE and an "other" category. Compliance can be through RECs or CERC-notified buyout routes. However, questions remain over CERC's authority under the Act and possible double-counting with RPOs under the Electricity Act.

8.3 Transmission charges, DSM, hydro concurrence

Inter-State transmission charges: CERC's Sharing of Inter-State Transmission Charges (Fourth Amendment) Regulations 2025 update the rules for sharing transmission charges under the GNA framework. They also revise the waiver periods and conditions for renewable energy, energy storage and green-hydrogen projects. Force-majeure provisions allow eligible projects to retain these waivers, while storage projects can comply through self-declaration.

Hydropower and pumped storage: A Ministry notification provides that CEA concurrence is required only for hydro projects with an estimated capital cost above ₹3,000 crore. Off-stream closed-loop pumped storage projects are exempt from CEA concurrence regardless of their cost, although they may seek technical guidance from CEA if required. This reduces the requirement for prior public technical scrutiny of such projects. Safety is instead largely placed on the project developer's obligation to "adhere to" the Dam Safety Act. This is significant because private

investment in pumped storage is rapidly increasing and it will make further possibilities of environmental accidents.

8.4 Coal-side deregulation

Mine-opening approvals: The Colliery Control (Amendment) Rules 2025 transfer approval for opening coal mines from the Coal Controller to the company's Board. The company only has to inform the authorities afterwards. This will further reduce the public scrutiny and designed for private mine operators.

Sale of surplus linkage coal: Under the revised SHAKTI policy, Coal India Limited (CIL) can sell unrequisitioned surplus coal from linkage-coal-based power stations through power exchange. This actually creates tendency of speculative trading in coal also.

Coal and lignite gasification: The Cabinet has approved a ₹37,500 crore scheme to promote coal and lignite gasification. The scheme can provide support of up to 20% of the cost of plant and machinery, with a target of gasifying 100 million tonnes of coal and lignite by 2030.

GST and electricity tariffs: CERC, through a suo motu order, has treated the abolition of the GST compensation cess on coal and the increase in GST from 5% to 18% as a "Change in Law" event under Section 63 PPAs. The resulting net financial impact is passed on to DISCOMs and, ultimately, electricity consumers through tariffs.

8.5 FGD rollback

Based on a NITI Aayog–CSIR-NEERI report, the MoEF&CC revised the 2015 Flue Gas Desulphurisation (FGD) mandate in July 2025.

- Category A: Thermal power plants located within 10 km of the NCR or million-plus cities must install FGD by December 2027.
- Category B: Plants in critically polluted or non-attainment areas will be considered for FGD on a case-by-case basis.

- Category C: Around 78% of India's thermal power capacity has been exempted from the FGD requirement.

The government's justification is that Indian coal contains relatively low sulphur (0.35–0.4%), ambient SO_2 levels are below the prescribed standards in most regions, FGD costs around ₹1–1.2 crore/MW, and it could increase electricity tariffs by about 50–55 paise per unit.

Following the change, NTPC instructed BHEL to suspend FGD work at Lara-II, Singrauli-III, Sipat-III, Darlipalli-II and Telangana-II.

However, a national average showing relatively low SO_2 levels does not necessarily address local pollution and public-health risks around individual thermal power plants. Exempting about 78% of thermal capacity therefore raises concerns about pollution exposure in nearby communities and the long-term health and environmental impact.

8.6 Jan Vishwas and the Electricity Act

The Jan Vishwas (Amendment of Provisions) Act 2026 covers 79 Central Acts and decriminalises 717 provisions. For the Electricity Act, the Ministry notified 1 June 2026 as the date for implementing the scheduled amendments.

The changes replace some criminal provisions with higher monetary penalties, including penalties for damage to electricity works. Section 141, relating to extinguishing public lamps, has been omitted, while Section 142 has been expanded. However, for safety violations, consumer harm, environmental breaches and attacks on critical electricity infrastructure, monetary fines may not provide sufficient deterrence if large companies can simply treat them as a cost of doing business.

8.7 Cybersecurity

During Operation Sindoor in 2025, nearly two lakh cyber-attack attempts were reported against the power sector, although no nationwide blackout occurred. The CEA has therefore introduced

tighter requirements for protecting sensitive operational data and systems.

As SCADA systems, smart meters, cloud platforms and electricity-market platforms become increasingly digital, cybersecurity is now an important part of energy security. These security standards must apply equally to private licensees and power exchanges as well as public utilities, since a cyberattack on any part of the electricity system can affect the wider grid. With private grid operation, the risk of cybersecurity breach increases.

9. Nuclear power: public milestone, private opening

9.1 SHANTI Act and private entry

Parliament passed the SHANTI Act in December 2025, replacing the Atomic Energy Act, 1962 and the Civil Liability for Nuclear Damage Act, 2010. It brings licensing, liability and regulation under one law and allows Indian private companies to build, own, operate and decommission nuclear plants.

The Union Budget 2025-26 announced a ₹20,000 crore Nuclear Energy Mission, including five indigenous SMRs by 2033 and a target of 100 GW nuclear capacity by 2047. Adani, Reliance, Tata Power, Vedanta and Jindal have shown interest. Adani Power has announced plans for up to 10 GW by 2035, while NTPC and EDF are studying EPR technology, localisation, tariffs and sites.

A major concern is the withdrawal of statutory supplier liability for defective equipment or materials. Under the 2010 law, operators could seek compensation from suppliers in specified circumstances, including defective equipment. The SHANTI Act removes defective supply as a statutory ground and leaves such liability mainly to contracts.

This weakens an important incentive for suppliers to maintain the highest safety standards, particularly because nuclear defects may have consequences only after years of operation. It also raises the question of who ultimately bears the cost of a major accident. The SHANTI framework places primary liability

on the operator, while additional liability ultimately involves the Central Government and public funds.

Nuclear power is strategic, long-lived and high-risk infrastructure. Strong independent regulation, safety oversight, financial security and accountability across the entire nuclear supply chain are essential. India's proven public-sector capabilities through NPCIL, BHAVINI, BHEL, IGCAR and BARC must remain central to this framework.

9.2 Kalpakkam PFBR

On 6 April 2026 at 20:25 hrs the 500 MWe Prototype Fast Breeder Reactor at Kalpakkam achieved first criticality. Design is IGCAR's; construction and commissioning are BHAVINI's; fuel is uranium–plutonium MOX with sodium coolant. AERB had cleared the approach after a full safety review. Construction began in 2004; cost has risen to the order of ₹8,000 crore. The event is Stage Two of Homi Bhabha's three-stage programme and the bridge to a thorium cycle. It is an achievement of the public scientific estate, not of the new private nuclear companies.

10. Renewables on the ground: curtailment, rooftop and "green capitalism"

A contradiction that has not gone away is this. India hit the 50 per cent non-fossil capacity mark early, while solar plants in Rajasthan were being curtailed from March 2025 — about 4 GW, losses up to ₹250 crore, curtailment exceeding 48 per cent of peak solar output on some days — because the public transmission system couldn't keep pace with indiscriminate private capacity addition. Punjab (up to 44 per cent), Tamil Nadu and Karnataka faced similar congestion. This is not an argument against renewables. It is an argument against auctioning generation faster than the public grid and storage can absorb it.

PM-Surya Ghar: Muft Bijli Yojana was recast so that States can top up Central CFA; residential CFA is ₹30,000/kW for the first 2 kW and ₹18,000/kW for the next 1 kW (higher in special-category States), with a 3 kW cap, domestic-module condition and a five-year vendor-maintenance mandate. The industrial

beneficiaries of the rooftop push are visible in company accounts: Tata Power's FY 2024-25 renewables surge and roughly 20 per cent EPC share of the rooftop market; Adani Green's quarterly profit rise; module-makers expanding cell and module lines. Households get a capital subsidy. The solar panel industry gets a market and the DISCOM loses it.

MNRE and the Ministry of Power withdrew the Uniform Renewable Energy Tariff (URET) pool in 2025 after procurers delayed signing Power Sale Agreements (PSAs) because of price variations during the contract period. Bids already awarded continue separately. The episode shows a wider problem: administrative mechanisms designed to provide price stability can come under pressure when renewable bid prices fall and procurers become cautious about committing to higher or variable prices.

11. Public-sector capability, BRICS and manufacturing

BHEL manufactured India's first set of indigenous SCR catalysts for NOx control at thermal power stations, replacing earlier imports, and received orders for Yadadri, Bhusawal, Sagardighi and Damanjodi. This is the kind of public manufacturing capability that the energy transition requires.

BRICS 2026, hosted by India, focused on critical minerals, battery storage, smart grids, biofuels and clean-energy manufacturing, including a Digital Centre of Excellence for Smart Grids and Energy Storage. Such cooperation is useful only if it strengthens Indian public companies, research institutions and domestic manufacturing. Critical minerals, grids and storage cannot be left entirely to private concessionaires.

The Ministry of Mines approved 58 companies under the ₹1,500 crore critical-mineral recycling incentive. Building recycling capacity is necessary, but the ownership and offtake of recovered lithium, nickel and rare earths are strategic issues, not merely matters of ESG.

12. Investment summits and the $2.2 trillion story

At the Bharat Electricity Summit 2026 the Prime Minister invited global investors and technology firms into Indian power and cited a requirement of nearly USD 2.2 trillion over two decades for RE, transmission, storage, smart metering and digital systems. The summit is the public face of the Draft NEP: the sector is being pitched as a globally integrated investment ecosystem. Transmission corridors, STATCOMs, BESS and meters are technically necessary. An investment conference is not a resource-adequacy plan, and it is not a social compact with the farmer and the household.

13. Kerala's CAPEX model for smart metering

Under RDSS the Centre pushed a TOTEX AMI programme for KSEB — a private service provider to own meters, software and communication and recover the cost from the Board over 93 months, with only a 15 per cent grant. EEFI treated this as a back door to privatising metering and revenue: content separated from carriage. The alternative placed before the Government of Kerala was CAPEX — the Board buys and owns the assets, staff install, K-FON carries the data, the KSEB data centre stores it. The 2023 TOTEX tender for 37 lakh meters came in 44.8 per cent above estimate. On 25 August 2023 the State accepted the CAPEX route.

Phase I (three lakh meters) proved the arithmetic. Bids opened in January 2025 were 24–55 per cent below estimate. A single-phase meter cost about ₹60 a month under CAPEX against ₹80 under TOTEX; an LT-CT meter about ₹113 against ₹283. Phase II, for 50 lakh meters, was tendered in February 2026. After the Assembly election, pressure and a planted media story sought to scrap the live tender and restore TOTEX. The unions refused that trap. Bids opened on 5 September 2026: GridCrest was lowest at ₹3,241 crore; Adani finished last among technically qualified firms. The discovered average is about ₹2,800 a meter — a national low, roughly one-fourth of the 2023 TOTEX rate.

On 26 September 2026 the ministerial meeting at Kochi confirmed that Kerala will continue smart metering on the

CAPEX model. EEFI did not oppose smart meters. It opposed the private sector operation and control. The work now is to finish Phase II on schedule and refuse any fresh attempt to bring TOTEX back.

14. What the eighteen months demonstrate

Seven conclusions follow from the record before the Council.

First. Nameplate capacity is not electricity security. 556 GW and 55 per cent non-fossil did not prevent 7.7 GW night shortages, Rs 20/unit exchange prices, or daily cuts in electricity distribution.

Second. The missing elements are firm evening–night capacity, storage, flexible hydro and thermal, fuel logistics and transmission — all of which are planning and public-investment problems, not auction problems.

Third. Parallel licensing, data-centre-only licences, open access, rooftop migration and DISCOM IPOs are part of a single mechanism. They move high-value load to private balance-sheets and leave universal service, agriculture and the wires with the public utility.

Fourth. Market coupling, VPPAs, futures, capacity markets and shorter RTM windows deepen financialisation. Scarcity conditions show the limit of relying on a spot market for an essential service. The Electricity Act's consumer-protection objects are not met when DISCOMs must buy at the ceiling and still shed load.

Fifth. Nuclear and hydro remain strategic public capabilities. PFBR criticality is a public-science achievement. The SHANTI opening and the Adani 10 GW announcement are a different project and should be treated as such.

Sixth. The Draft NEP 2026 rewrites history so that leftover access and evening scarcity become a DISCOM-discipline problem, then completes the unfinished business of 2003 in intra-State transmission, the distribution wire, storage and nuclear. Public money is to de-risk private return. That is one design, not a set of technical chapters.

Seventh. Resistance works. Tata Power's withdrawal in Karnataka, the delay of the Amendment Bill, the public campaign against Eleven Power in Gurugram–Nuh, the continuing fight over Puducherry and Maharashtra licences, and Kerala's defence of the CAPEX meter model and its ministerial confirmation — are the reason the legal architecture is not yet a fait accompli.

Implications for EEFI work

The Conference line stands: do not allow another inch on privatisation of distribution; keep generation of strategic value,

the wires and the meters in public hands; treat contract regularisation as the workplace face of public power; build worker–consumer forums so that tariff shocks, prepaid meters and evening cuts are fought with households and farmers, not only inside the union office.

On the industry side the immediate tasks are specific. Contest every parallel-licence petition with the Haryana-style record — revenue share of the proposed area, book value of the public network, cherry-picking arithmetic. Carry the Kerala CAPEX arithmetic into every State where RDSS is being used to push TOTEX AMISPs. Insist that resource-adequacy plans count dependable MW at 19:00–24:00, not only GW of solar. Answer the Draft NEP paragraph by paragraph on access definitions, USO exemption, listing and capacity markets – fight it. Oppose coupling and MBED insofar as they strip State utilities of procurement autonomy. Demand that storage and pumped-hydro expansion be public-led. Keep nuclear inside a public-liability, public-operator frame. Treat cybersecurity, FGD/public-health rollbacks and Jan Vishwas decriminalisation as part of the same weakening of public accountability.

If we don't stand strong today, the 11th Conference will meet a sector that is larger, greener on paper, more private in the profitable slices, and less secure after sunset than the sector the 10th Conference inherited. Let's prepare ourselves to protect our assets and rights.