Grid Lines and Bottom Lines

Analysis of the Financial Performance of Electricity Distribution Companies

Study for the Sixteenth Finance Commission of India

Prayas (Energy Group)

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by
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September 2025

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List of Abbreviations

Abbreviation	Full Form	Abbreviation	Full Form
ACOS	Average Cost of Supply	kWh	Kilowatt-hour
AG	Agriculture	LoA	Letter of Award
AES	AES Corporation	LT/ LV	Low Tension/ Low Voltage
AP	Andhra Pradesh	MERC	Maharashtra Electricity Regulatory Commission
APTEL	Appellate Tribunal for Electricity	MoP	Ministry of Power
ARR	Aggregate Revenue Requirement	MSEDCL	Maharashtra State Electricity Distribution Company Limited
AT&C	Aggregate Technical and Commercial (losses)	MSKVY	Mukhya Mantri Saur Krushi Vahini Yojana
AVVNL	Ajmer Vidyut Vitran Nigam Limited	MU	Million Units
BESS	Battery Energy Storage System	MW	Megawatt
BRPL	BSES Rajdhani Power Limited	MWh	Megawatt-hour
BYPL	BSES Yamuna Power Limited	NBFC	Non-Banking Financial Company
C&I	Commercial and Industrial (consumers)	NEP	National Electricity Plan
CAG	Comptroller and Auditor General	OA	Open Access
CBAM	Carbon Border Adjustment Mechanism	OERC	Odisha Electricity Regulatory Commission
CEA	Central Electricity Authority	OTC	Over The Counter
CERC	Central Electricity Regulatory Commission	PFC	Power Finance Corporation
CESCO	Central Electricity Supply Company of Odisha	PM-KUSUM	Pradhan Mantri Kisan Urja Suraksha evam Utthaan Mahabhiyan
CESC	Calcutta Electric Supply Corporation	PSPCL	Punjab State Power Corporation Limited
CESU	Central Electricity Supply Utility of Odisha	RBI	Reserve Bank of India
DISCOM	Distribution Company	RDSS	Revamped Distribution Sector Scheme
DDUGJY	Deen Dayal Upadhyaya Gram Jyoti Yojana	RE	Renewable Energy
DF	Distribution Franchisee	REC	Rural Electrification Corporation
DT	Distribution Transformer	RfP	Request for Proposal
DVB	Delhi Vidyut Board	SCI	Supreme Court of India
ERC	Electricity Regulatory Commission	SEB	State Electricity Board
ESG	Environmental, Social, and Governance	SECI	Solar Energy Corporation of India
FD	Fiscal Deficit	SERC	State ERC
FDRE	Firm and Dispatchable Renewable Energy	SEZ	Special Economic Zone
FRP	Financial Restructuring Plan	SLR	Statutory Liquidity Ratio
FY	Financial Year	SLDC	State Load Dispatch Centre
GDP	Gross Domestic Product	SMK	Shil, Mumbra and Kalwa
GoG	Government of Gujarat	T&D	Transmission and Distribution
GoM	Government of Maharashtra	TANGEDCO	Tamil Nadu Generation and Distribution Corporation
GRIDCO	Grid Corporation of Odisha Limited	TNERC	Tamil Nadu Electricity Regulatory Commission
GSDP	Gross State Domestic Product	ToD	Time of Day (tariffs)
GWh	Gigawatt-hour	TPL	Torrent Power Limited
HT	High Tension/High Voltage	TPDDL	Tata Power Delhi Distribution Limited
IEX	Indian Energy Exchange	Tx	Transmission
IESA	India Energy Storage Alliance	UDAY	Ujwal DISCOM Assurance Yojana
JdVVNL	Jodhpur Vidyut Vitran Nigam Limited	UP	Uttar Pradesh
kW	Kilowatt	UPERC	Uttar Pradesh ERC

Grid lines and Bottom lines

Analysis of the financial performance of electricity distribution companies

Summary

Background and Context

India's electricity sector is only as financially robust as its most critical link—the electricity distribution companies (DISCOMs) that interface with end consumers. With ₹7.08 lakh crore[1] in accumulated DISCOM losses growing at 8% per annum on average, the sustainability of the entire sector's value chain hangs in the balance. DISCOM financial challenges have been long-standing, persisting despite multiple financial restructuring schemes over decades. While addressing past losses is crucial, stemming the build-up of future losses is also a critical aspect, which has been tough to address in the past.

With mounting losses as well as liabilities, policy-makers at both central and state levels are contemplating another comprehensive financial restructuring effort. This effort, has the potential to be fundamentally different with long-lasting implications, provided it leverages two recent developments in the sector. First, cost-competitive renewables and storage now offer viable pathways to reduce power procurement costs for DISCOMs and consumers while ensuring reliable supply. This addresses the primary challenge of high power purchase costs that remained largely unresolved in earlier reform cycles. Second, substantial investments over the past two decades in network infrastructure, supply reliability, and electricity market development have created the foundational conditions necessary for deeper structural reforms and transformation of business models that were simply not feasible even a decade ago.

This study examines recent sector developments, particularly those following the launch of the *Ujwal DISCOM Assurance Yojana* (UDAY) in FY16 and the policy and techno-economic transformations that have reshaped the distribution business since 2020. It assesses the major drivers of increasing DISCOM losses and offers recommendations to address past losses while preventing future liability accumulation. In the context of the sector's changing techno-economics, it also explores how DISCOMs can restructure their operations and business models to ensure long-term financial sustainability.

Schemes to address losses and liabilities of DISCOMs

DISCOM financial challenges have persisted despite multiple financial restructuring schemes over decades. Between 2001 and 2015, there have been four major schemes to address DISCOMs' past liabilities: the State Electricity Board (SEB) Bailout scheme of 2001, the Transfer Scheme under Section 131 of the Electricity Act,2003, the Financial Restructuring Plan (FRP) in 2012, and the most recent debt takeover under the UDAY in November 2015[2].

Evidence demonstrates that comprehensive debt takeover does improve DISCOM finances. This is clear from Rajasthan and Haryana where growth in accumulated losses has been arrested since the debt takeover under UDAY. About ₹2.21 lakh crore was taken over nationally under UDAY, accounting for 62% of total liabilities in FY16. In contrast, state governments in Tamil Nadu and Madhya Pradesh took over only 34% and 37% of total liabilities under UDAY

[1] As on 31st March 2024 the accumulated losses reported by DISCOMs was ₹7.08 lakh crore.

[2] More details in Section 3.1 and Section 3.2 of the report

respectively. In these states, legacy losses and interest costs continue to undermine current financial viability.[3]

UDAY also stipulated a phase-wise annual loss takeover after FY16 such that 50% of annual losses by FY21 was taken over by the state government. About ₹26,837 crore was taken over in seven states[4], which is only 15% of the losses on average for the period FY17–FY23[5].

Since UDAY, there have been other national initiatives to improve the financial viability of the sector, especially the Liquidity Infusion Scheme (LIS), the Late Payment Surcharge (LPS) scheme, the Revamped Distribution Sector Scheme (RDSS), and an increase in borrowing limits subject to power sector conditionalities as recommended by the 15th Finance Commission. The focus of the Liquidity Infusion Scheme and the Late Payment Surcharge rules was to clear pending dues to generators and transmission companies and ensure payment discipline of DISCOMs. Under these schemes, DISCOMs have borrowed close to ₹2.5 lakh crore in working capital loans, accounting for about 36% of total DISCOM borrowings. RDSS provided necessary support for essential capital investments to these cash-strapped DISCOMs. Along with the conditionalities for additional borrowing, RDSS has also resulted in improvements in timely payments of subsidies[6] and dues from government department in some states[7], partial takeover of annual losses in some states[8], and improvements in financial reporting in many states[9]. However, future efforts are needed to sustain these early gains.

Major contributors to increasing losses and liabilities of DISCOMs

Analysis of DISCOM operations and finances since FY16 identifies the following major contributors and trends in present financial challenge before DISCOMs.

a. **Build-up of working capital liabilities:** About 44–86% of total borrowings by the DISCOMs in eight states[10] is reported to have non-capex end use. Such working capital borrowing has results in annual interest cost to the tune of 5% of the DISCOMs' expenses. The DISCOMs in these eight states account for 43% of total accumulated losses. It is highly likely that such dependence is also relevant for other DISCOMs in India. This reliance on working capital borrowing creates a cascading effect: inability to invest in networks, sustained dependence on central grants for capital investment, reduced resources for critical maintenance works and a mounting interest burden that further weakens DISCOMs' financial health. Another

[3] Please see Section 3.2.1 of the report.
[4] Tamil Nadu, Telangana, Uttar Pradesh, Madhya Pradesh, Punjab, Meghalaya and Haryana.
[5] Please see Section 3.2.2 of the report.
[6] Of the 12 states that account for 90% of the subsidy billed nationally, subsidies were paid on time in 10 states in FY22 and 11 states in FY23. However, delays in subsidy payment were noted in five of these states in FY24.More details in section 4.4 of the report.
[7] By FY24, the quantum of government dues had reduced significantly in Maharashtra and Telangana, and marginally in Rajasthan. However, despite RDSS conditionalities requiring clearance of pending government dues, the outstanding amounts increased starkly in Uttar Pradesh and Andhra Pradesh, and rose marginally in Tamil Nadu and Madhya Pradesh by FY24. More details in Section 4.4 of the report.
[8] Annual loss takeover by states totalled ₹23,200 crore in FY22 and ₹43,600 crore in FY23. In FY22, the Tamil Nadu government took over ₹11,954 crore, followed by ₹17,117 crore in FY23 and ₹19,090 crore in FY24. This accounts for 60% to 75% of the annual losses of the DISCOM in this period. In fact, the Tamil Nadu state government assumed 52% of the overall national takeover in FY22 and 39% in FY23. More details in Section 3.3.3 of the report.
[9] This is the case with clear reporting of working capital borrowing in five states, details of state government guarantee to loans in nine states, reporting of age-wise receivables in eleven states, reporting of subsidy payments in eight states and reporting of government department dues in nine states
[10] Andhra Pradesh, Bihar, Haryana, Karnataka, Maharashtra, Punjab, Rajasthan and Telangana. More details in Section 4.5 of the report.

crucial indicator of financial stress is that state-owned generation and transmission companies have substantial pending dues from DISCOMs, which are yet unaddressed under the LPS and LIS schemes[11].

b. **Issues with power procurement planning and pricing**: Lack of periodic assessment of demand-supply requirements, absence of least-cost planning approaches, and challenges with fuel availability and price volatility were observed in multiple states[12]. As power procurement contributes to 70% or more of the DISCOMs' expenses, optimisation in operations and least cost planning approach will reduce costs significantly.

c. **Delays in regulatory dispensations due to ongoing disputes:** Disputes between parties and appeals against state electricity regulatory commission (SERC) orders remain pending before the Appellate Tribunal for Electricity (APTEL) for years, creating uncertainty and carrying cost build-up. This is further exacerbated by unfilled vacancies in APTEL, which contribute to this uncertainty[13].

d. **Inadequate and infrequent tariff increases**: Despite policy initiatives to ensure timely annual tariff orders over the past decade, a marginal improvement in tariff revision has been observed after UDAY. When tariff orders are issued, no tariff increase is approved in 40% to 60% of instances in Telangana, Tamil Nadu and Rajasthan and in 20% to 30% of instances in Uttar Pradesh and Madhya Pradesh[14].
When tariff increase was approved, often the tariff increase was significant. Of the years where tariff increase was approved, a tariff increase of more than 10% was observed in 40% of the cases in Rajasthan, 29% of the years in Uttar Pradesh and 13% and 17% of cases in Telangana and Madhya Pradesh respectively.

e. **Delays in revenue recovery and subsidy payments:** The growing dependence on subsidies makes timely subsidy payments critical for managing DISCOM operations and reducing working capital borrowing requirements. Between FY16 and FY24, delays in subsidy payments resulted in a cumulative interest cost buildup of ₹26,500 crore nationally[15].
Outstanding consumer dues present another major challenge. Approximately 40% of receivables in the five states[16] that account for the bulk of outstanding amounts in FY24 are over three years old, indicating limited recovery prospects and necessitating either provisioning or state government intervention. Despite significant financial losses, Tamil Nadu, Rajasthan, and Kerala maintain receivables days at manageable levels. In contrast, Uttar Pradesh shows high receivables even after recent improvements, while Madhya Pradesh, Maharashtra, and Telangana which had significant outstanding consumer dues around FY16 have also shown a sharp increase in dues in recent years[17]. Significant consumer dues are from government departments and public bodies especially in Tamil Nadu, Andhra Pradesh, Uttar Pradesh and Rajasthan.

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[11] Section 4.5.4 of the report.
[12] Section 4.1
[13] Section 4.2
[14] Section 4.3
[15] Section 4.4
[16] Uttar Pradesh, Telangana, Maharashtra, Andhra Pradesh and Karnataka.
[17] Section 4.4 and Annexure 7.

f. **Significant progress in Aggregate Technical and Commercial (AT&C) loss reduction and its implications for the future**: Demonstrable improvements in AT&C loss reduction have occurred in the past decade due to improvements in collection efficiency and lower distribution losses. In FY14, 10 states[18] reported AT&C losses of about 40% or more, but only three states reported losses higher than 40% in FY24.[19] However, future improvements would require sustained and substantial capital investment, efforts to address long pending receivables by state governments, as well as concerted efforts to perhaps re-state and then reduce distribution losses[20].

Strategies to address challenges and their potential impact

The primary levers as well as future cost implications of addressing these challenges are discussed below:

a. **Takeover of losses/liabilities by state governments through bond issuance:** The bonds could be structured as 20-year instruments, with the takeover phased across five tranches to manage the fiscal impact on states. Based on available data, taking over cumulative and annual losses totalling ₹7.45 lakh crore in FY24 across 22 states would cost approximately ₹70,000 crore annually for the entire 20-year bond period if done as a one-time takeover. However, with a phased tranche-wise approach, the annual national impact starts at ₹15,400 crore in Year 1 and increases to ₹92,425 crore from Years 5 to 20. The fiscal impact varies from 0.02% to 0.45% of Gross State Domestic Product (GSDP) in the 10 states which account for 90% of accumulated losses, indicating that fiscal impact can be managed with GSDP growth[21].

b. **Least cost planning approach for power procurement**: Increasing solar and wind generation can significantly reduce or halt growth in power purchase costs. However, this transition requires comprehensive strategies to maintain grid reliability including flexible operation of existing coal and hydro plants, demand-side management to align consumption with renewable availability, and substantial energy storage investments. New coal capacity should only be considered in case found a least-cost reliability solution, given large capital requirements, relatively high gestation periods and likely reduced utilisation in a renewable-dominated grid. Without careful planning, addition of significant coal capacity risks stranded assets that impose substantial costs on DISCOMs.

c. **Solarisation of agriculture**: An effective approach to integrating large amounts of low-cost solar energy involves aligning agricultural power supply with solar generation hours. Agricultural consumers account for 25% of consumption and receive about 90% of state government subsidies. To achieve rapid solarisation at scale, 2-10 Mega Watt (MW) of grid interactive solar capacity can be contracted via competitive bidding at the dedicated agricultural feeder level catering to multiple agricultural consumers. If solarised agricultural feeders can supply energy to meet 50–70% of electricity consumption of farmers by 2032,

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[18] Bihar, Odisha, Meghalaya, Tripura, Jharkhand, Sikkim, Arunachal Pradesh, Manipur, Nagaland and Jammu and Kashmir.
[19] Arunachal Pradesh, Nagaland and Jammu and Kashmir.
[20] Please see Section 5.4.2 of the report.
[21] Please see Section 5.1.2

the annual cost and subsidy savings would range from ₹77,000 crore to ₹90,000 crore per year at the national level. Rapid scaling of solarisation is possible with alignment of agricultural consumption with solar hours, continuation of capital investment grants to support feeder segregation and continuation of central financial assistance of ₹1.05 crore per MW to developers. This can be limited to the first 20,000 MW deployed to incentivise rapid scaling[22].

d. **Inflation-linked tariffs**: Instead of infrequent and at times large tariff increase, annual tariff increase can be linked to inflation, which at modest tariff increase levels would be critical towards timely revenue recovery for DISCOMs. Had such inflation-linked tariff increases been implemented during FY16–FY23, the accumulated revenue gap would have decreased by ₹4.41 lakh crore, translating to an annual additional revenue recovery of ₹60,000 crore, eliminating ₹1.6 lakh crore in interest costs. The increased revenue recovery would have been through an average tariff increase of just 3.9% with state-specific variations, which is only marginally higher than the actual average tariff increase observed in the same period. The proposed approach institutes regular and predictable tariff increases creating more stable and certain pricing for consumers. Adoption of inflation linked tariffs can be incentivised in states with: (1) regulatory assets or cumulative revenue gaps exceeding 3% of revenue or (2) working capital borrowings account for more than 50% of total borrowings[23]. This measure should be complemented with adoption of renewables reflective time of day pricing and regular fuel surcharge adjustments.

e. **Compliance and reporting of timely payments to continue as part of conditional central sector assistance**: Capital investment support in central sector schemes should ideally continue to be conditional on timely payment of state government subsidies and government department dues. This should be complemented with centralised public reporting on pending subsidies and government department dues to ensure that the gains in terms of payment discipline through such measures are sustained and scaled.

f. **With significant reduction achieved in the past, AT&C Loss reduction may not be a priority future strategy in many states with high financial losses:** AT&C loss reduction depends on two key actions: reducing distribution losses and improving revenue recovery from consumers. The combined impact of achieving an additional 1.15% distribution loss reduction beyond FY24 actuals and halving outstanding receivables would generate annual savings of ₹16,260 crore. This represents average annual cost savings of 1.6% of DISCOM expenses. Halving of outstanding receivables itself entails significant efforts. Further, improvement in collection efficiency is constrained because 52% of ₹96,422 crore in receivables is over two years old and likely unrecoverable without state intervention. Although AT&C loss reduction remains important for operational efficiency and financial sustainability, the gains from this reduction are not sufficient to address the financial challenges facing DISCOMs. Rather than focus on AT&C loss reduction, DISCOMs and state governments should prioritise a comprehensive approach that integrates multiple cost optimisation and revenue recovery strategies to achieve transformational improvements in the power sector's financial health.

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[22] Please see Section 5.3

[23] Section 5.5.1 of the report

Experience with Privatisation

The privatisation from Delhi and Odisha show that privatisation can improve service quality and reduce AT&C losses but requires substantial state support, including liability takeover, transition financing, and subsidies or capital grants. Political economy constraints also persist for the private utilities through delayed tariff adjustments and regulatory uncertainty. Further, the cost-plus structures limit efficiency incentives, and the necessary conditions for replication (high AT&C losses, poor service quality and a significant paying consumer base) may not exist in all states[24].

Input-based franchisees appointed by DISCOMs provide an alternative model for private participation, targeting very high-loss pockets while ensuring fixed revenues for DISCOMs. The model saw early success in Bhiwandi and generated significant interest. However, only 11 of 28 franchisees appointed across nine states remain operational. Failures were largely due to non-payment of dues or poor performance (52%), operational challenges, or on-the-ground opposition (23%). Success depends on transparent competitive bidding, comprehensive baseline surveys, clear performance benchmarks, and robust regulatory oversight[25].

It is crucial that states adopt private participation models through competitive bidding only when necessary and appropriate for the state context. Many of these models may not be suitable for states with manageable AT&C loss levels, good service quality but poor finances. Input-based franchisees are perhaps best suited for high-loss pockets where AT&C losses are more than double the national average (32%). In such cases, the agreements should specify loss-reduction trajectories, transparent monitoring, arrear recovery, and capital investment. They should also include significant penalties for delay in payment of dues and provide contract renewal options based on performance. Privatisation of the entire DISCOM should be considered only in states with persistent AT&C losses, poor network management, and unsuccessful franchisee experience. Successful privatizations underline the importance of substantial state support through liability takeover, additional transition finance support and in-kind support through capex grants and power procurement. Pre-privatisation measures are also crucial: maintaining an asset registry, consumer indexing, streamlining billing and revenue collection, and establishing baseline AT&C losses.

It is important to explore models for private participation which can improve network investment and reliability and which are not just focussed on AT&C loss reduction. State governments and DISCOMs can test new frameworks to attract investment and strengthen reliability including competitive bidding for sub-transmission and distribution assets and Operation and Maintenance (O&M) franchisees for specific feeders or divisions[26].

Emerging trends which can impact future operations of DISCOMs

DISCOMs in India are already facing disruptive shifts which will fundamentally affect the structure of the electricity sector and their future business model. Because some of these changes are inevitable, not addressing them in a systematic manner would adversely affect the future financial position of DISCOMs.

[24] Section 6.3
[25] Section 6.4 of the report
[26] Section 6.5

a. **Cross-subsidy from Commercial and Industrial (C&I) consumers is no longer a major contributor to DISCOM revenue[27].** Traditionally, DISCOMs relied heavily on cross-subsidies to provide tariff support to the residential and agricultural categories. However, with increasing open access and captive sales and regulatory steps to reduce cross-subsidy in tariffs, cross-subsidies now account for less than 10% of revenues. At the same time, direct state subsidies contribute between 10% and 47% of the revenue. This increasing dependence on state budgets and reduced reliance on cross-subsidies changes the traditional structure in which retaining typically cross-subsidising C&I consumers was vital to the financial viability of DISCOMs.

b. **Agricultural solarisation is being adopted at large scale to reduce cost and subsidies rapidly[28]:** Maharashtra, Gujarat, Rajasthan and Andhra Pradesh are rapidly scaling feeder-level and centralised solar capacity to meet agricultural demand. Maharashtra alone has contracted nearly 18.7 GW, covering around 85% of its agricultural consumption and saving ₹4,000 to 5,000 crore annually for the DISCOM and the state governments.

c. **The ability and appetite of C&I consumers to invest in renewable-energy-based captive supply is substantial and growing, driven by the falling costs of solar and storage and an enabling regulatory framework[29]**: The economics have become increasingly compelling. Over the past two years, storage technology costs, particularly battery storage, have declined rapidly. As a result, solar-plus-storage solutions can now meet over 90% of industrial demand at less than ₹6 per unit—lower than industrial energy charges levied by DISCOMs for supply in 21 of 28 states. This cost advantage will further increase consumption from sources other than the DISCOM among C&I consumers. In Karnataka, Tamil Nadu, Gujarat, and Madhya Pradesh, 15% to 60% of C&I sales in the state is met through captive and open access routes. Notably, in Karnataka, Tamil Nadu, and Maharashtra, most non-DISCOM sales reported by DISCOMs are attributable to renewable-based captive supply, demonstrating the clear preference for cost-competitive, clean energy solutions. Supporting this transition is existing open access regulations and recently introduced frameworks for green open access and rooftop solar, which facilitate RE-based captive supply, open access, and net metering across almost all states. Looking ahead, sales migration will accelerate and be driven primarily by captive renewable energy, creating significant implications for DISCOM revenue recovery, power procurement planning, and costs.

d. **DISCOM pricing for reliability services to migrating consumers not compensatory[30]**: DISCOMs are currently the only providers for reliability services (banking and standby) to open access and captive consumers. However, these services are priced far below cost. Even with under-pricing, DISCOMs would have been compensated with open access charges. However, captive users are exempt from open access charges, leading to notional revenue losses of around ₹28,500 crore annually for DISCOMs. As volume of captive sales increase, DISCOM losses are bound to increase without adequate compensation for reliability services. Therefore, there is a need for pricing reform for DISCOM services and development of reliable, robust alternatives for consumers to avail such services through market-based procurement.

[27] Section 7.1
[28] Section 7.2
[29] Please see Sections 7.3 and 7.4 of the report.
[30] Please see Section 7.5 of the report

e. **Significant improvements in High Tension (HT) network investments and metering**: The past two decades have seen significant improvement in network reliability and metering infrastructure, especially in the case of the HT network. Further, open access has been operationalised on the HT network for almost two decades. Therefore, the sector has significant experience with energy accounting, scheduling and grid management with multiple buyers and sellers in the HT network.

f. **Several new electricity market related initiatives have set the stage for future innovation**: Electricity markets are slowly expanding, but liquidity remains limited. Short-term markets account for just 11% of the total power traded, with DISCOMs still the dominant buyers. New developments such as market coupling, electricity futures and even virtual power purchase agreements (PPAs) are on the horizon, but their success will depend on stronger open access participation and standardised medium-term contracts.

The trends point towards a sector-wide structural transformation and transition in India's electricity sector and creates a compelling case for transitioning HT consumers from administrative operations and cost-plus regulated tariffs to a market-based pricing framework.

Proposal for Deregulation of HT Supply or Carriage and Content Separation for HT consumers[31]

For HT consumers, the proposed structural reform measure is to move away from power supply provided by a regulated monopoly service provider (i.e., the DISCOM) towards multiple competitive supply arrangements (i.e., the market). Operationalising a shift in DISCOMs' business model would require the following steps:

a. State governments and SERCs can mandate that all HT consumers should transition to competitive, unregulated supply within five to seven years.

b. Under this arrangement, after a transition period of five to seven years (as decided by the SERC), HT consumers would procure 100% of their electricity through market-based contracts. SERCs would no longer set tariffs for HT consumers, and DISCOMs would have no obligation to supply them.

c. DISCOMs may supply to these HT consumers at mutually negotiated rates, but their focus would shift to LT consumers. A strict regulatory ring-fence would ensure that Low Tension (LT) consumers are protected—DISCOMs' unregulated business losses cannot be recovered through LT tariffs.

d. Consumers should continue to pay regulated network charges for transmission and wheeling. For reliability, DISCOMs would act only as providers of last resort at a premium regulated tariff. The premium tariff can be at say 2 to 3 times the average cost of supply (ACOS) of the DISCOM. All other services—banking, standby, storage—must be sourced through market contracts.

e. Consumers gain access to multiple supply options subject to compliance with grid connectivity, metering and scheduling regulations and procedures. To strengthen access, State Transmission Utilities (STUs) or State Load Dispatch Centres (SLDCs) could be empowered to process open access applications directly, potentially transferring HT network assets from DISCOMs to STUs.

[31] Please see Chapter 8

f. To ease market participation, bulk supply licensees could be introduced at the national and state levels, offering standardised contracts (fixed durations, service types, payment/security terms). This would reduce transaction costs and enable smaller HT consumers to participate.

g. This fundamental switch to market-based procurement would represent a major change in the DISCOM business model and will result in revenue loss without commensurate cost reduction in the short term. However, in the long term, it would help streamline investments, reduce power procurement requirements and cost, and expand opportunities for market-driven revenue generation. To cushion revenue losses in the initial years and incentivise adoption, transition finance support could be provided, for example:
    i. Central government grants of up to ₹1/unit for three years for incremental open access or captive sales (approximately ₹7,900 crore/year).
    ii. A 'supply obligation charge' of ₹2.5/unit on open access and captive HT consumers, replacing current surcharges and expiring after five years, potentially yielding ₹53,000 crore/year for DISCOMs without any state government budgetary outgo.

This approach recasts DISCOMs as NETCOMs with obligations only towards LT consumers at regulated tariffs. The regulators' role shifts to market development, LT consumer protection and network oversight. Over time, competitive supply options could be extended to LT consumers, particularly with renewable integration and advanced metering. Such an approach would mitigate the power procurement planning risks faced by DISCOMs in the context of uncertainty in future demand and provide a clear framework for DISCOMs' roles and services. The approach is summarised in the Figure below.

PROPOSAL FOR HT SUPPLY DEREGULATION / CARRIAGE AND CONTENT SEPARATION FOR HT SUPPLY

No Regulated Tariffs for HT Supply: With 3 to 5 years advance notice, SERCs stop tariff determination for HT supply. HT Consumers find suppliers at negotiated tariffs. The change can take place via voluntary adoption by state government, SERCs.

Network to remain monopoly business: Transmission and distribution business remain cost-plus, with regulated tariffs for network services (wheeling, transmission).

Consumers can choose supplier: Can be from generators, traders, exchanges under open access. National/State Bulk suppliers trading via standardised contracts can be instituted. Need for simplified processes and removal of administrative barriers.

Balanced, risk-reward framework: DISCOMs compensated for services such as standby, banking, and provider of last resort.

Ring-fencing of regulated business: SERCs to ensure that costs of DISCOM's unregulated HT supply is not be passed onto LT consumers.

Transition finance support for 5 year period: The support to DISCOMs can be through a combination of supply obligation charge on HT consumers and government support.

Benefits

- Competitive choice for 25% to 35% of sales
- Supply based on market forces rather than administrative considerations
- Increased innovation in power procurement
- DISCOMs supply obligation only to LT, limiting future cost increase
- DISCOMs focus on network investments and service

Complementary Actions

- Strong institution for grid operations
- Accountability for service quality
- Cost-reflective frameworks for net metering/ net billing
- Inflation linked tariffs, renewables responsive Time of Day tariffs.
- Standard contracts on power exchanges
- O&M network franchisees, competitive bidding for sub-transmission assets

Suggested approach based on the findings of the report[32]

The path forward requires treating the financial recovery of DISCOMs as a strategic enabler of India's energy transition and economic growth objectives. All major financial challenges must be addressed within a coordinated five-to seven year framework to ensure the financial sustainability of the sector. Piecemeal approaches addressing individual components will yield sub-optimal results and fail to break the cycle of financial distress. In this context, the following approach is suggested:

a. State Governments can takeover entire outstanding non-capex liabilities by the issue of 20 year bonds. The takeover of losses could be either a one-time exercise or tranche-wise, spread over a three- to five-year period.

b. Whether one-time restructuring or phased takeover is chosen, DISCOMs should be subject to performance- and reform-linked conditions. To be eligible for the scheme itself, state governments and regulatory commissions should have put in place a framework for automatic levy of inflation-linked tariffs. This is particularly relevant for participating states where the *approved* regulatory assets/cumulative revenue gaps are greater than 3% of annual aggregate revenue requirement (ARR) or when more than 50% of total borrowing of the DISCOM is for working capital requirements/non-capex purposes.

c. In addition, state governments and DISCOMs should commit to aligning supply hours for agriculture with solar hours. This alignment is necessary for rapid solarisation of agricultural sales, which could result in substantial cost and subsidy savings.

d. To ensure continued payment discipline, state governments and regulators should also evolve clear frameworks and time-bound schedules for payment of dues to state-owned generators and transmission companies as well as timely payment of subsidies and government dues, with mandatory quarterly statements being reported by DISCOMs to the central government and SERCs, which should be made available in the public domain.

e. State governments along with DISCOMs should evolve a five year plan/power sector policy to reduce the revenue gap, rationalise electricity subsidy and implement cost-reflective tariffs which can include plans to reduce power procurement costs, increase capital investment, tariff related initiatives, evolving cost reflective frameworks for services to open access, captive and grid interactive renewable consumers. The plan could also include the contours of adopting HT deregulation approach.

f. To incentivise participation in the scheme, the central government can provide an Interest subvention of 1% for a five-year period on the bonds issued by the state government along with an additional one-time capital investment reimbursement to the tune of 2% of the liabilities taken over.

g. As part of the scheme, all states where agricultural sales exceed 10% of the total sales should release plans/policies with targets to solarise the majority of their agricultural consumption through centralised procurement or feeder-level solarisation by 2030. Enhanced capital support can be provided by the central government in states where

[32] Please see Chapter 9

agricultural demand is consistently more than 30% of sales, that is, Madhya Pradesh, Telangana, Karnataka and Rajasthan In addition, the central government could continue to provide financial assistance to the tune of 30% of the project cost for MW scale, feeder level projects for agricultural solarisation. However, this could be limited to the first 20,000 MW of agricultural solarisation PPAs.

h. To implement inflation-linked tariffs, SERCs should first approve cost and performance trajectories fixed for a five-year period under the Multi-Year Tariff (MYT) Regime.[33] In the tariff order, applicable for the five-year period, the Commission also determines a base year tariff and an efficiency factor fixed for a five-year period. Tariffs for subsequent years can then be automatically increased by the DISCOMs from 1st April of each year. The rate of increase would be based on the inflation rate for the power sector declared by RBI or the Central Electricity Regulatory Commission (CERC), which is adjusted with an efficiency factor fixed for five years by the regulatory commission in the MYT Order. Any revenue surplus revenue/gap should be adjusted at the end of the five-year period, when the tariff determination for the next five-year period will be considered.

i. For states opting for deregulation of HT supply within a five-year period, additional central government support of up to ₹1/unit for incremental open access sales from FY26 for three years could be provided. This could be enhanced, depending on the states' performance and requirements, to meet the strategic objective of moving a significant part of the power sector to market-based pricing and a competitive structure. In addition, transition finance could be raised through a 'supply obligation charge' of ₹2.5/unit from migrating consumers. This would translate to up to ₹53,000 crore/year for five years of support to DISCOMs without budgetary outgo. Such a charge should only be levied in states where state governments enable HT deregulation in the first five years.

j. To address the increasing complexity of the power sector and the growing caseload before APTEL, it is crucial to expand APTEL's capacity from the current 4 members and 1 Chairperson to 11 members and 1 Chairperson. Additionally, regional benches should be operationalised within a one-year time frame. The central government should also commission a comprehensive study to assess how APTEL's processes—particularly case management, staffing for regional benches and use of technology-enabled solutions—can be enhanced to improve efficiency, order quality and case pendency. Based on the study's recommendations, guidelines for improving APTEL's processes should be notified. Similarly, a review of regulatory commission processes and functioning is essential, which could be undertaken by an independent committee constituted by APTEL with representation from DISCOMs, Forum of Regulators, the MoP, academic institutions and sector experts.

In the absence of a comprehensive approach to manage legacy losses, mitigate present revenue recovery and operational efficiency challenges, and address impacts of emerging trends that affect DISCOM business, DISCOMs will continue to be trapped in a debt cycle. This leaves them unable to invest in improving service quality while maintaining high dependence on state governments for loss funding, capital investment grants, and subsidies.

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[33] The Multi-Year Tariff regulations have been notified by all SERCs, with the Forum of Regulators also issuing Model Regulations in 2011, 2023 and 2025 to aid adoption.

Measures towards reducing the cost of supply and instituting cost-reflective tariffs are necessary, but they must be contemplated alongside measures to mitigate the impact of increased migration of sales to open access and captive generation to prevent future loss accumulation.

The window for transformative structural change is open, but it requires coordinated action across multiple fronts—financial restructuring, regulatory strengthening, technological adoption, and business model innovation. This study provides both diagnostic analysis and actionable recommendations to tackle past and present losses while mitigating the risk of future loss build-up and introduction of greater competition and consumer choice. The choice is clear: embrace comprehensive structural changes now or face an even more challenging financial crisis in the future.

GRID LINES AND BOTTOM LINES

Contents

List of Figures

List of Tables

Grid lines and Bottom lines

Analysis of the financial performance of electricity distribution companies

1 Introduction

For over three decades, multiple reform and restructuring efforts have attempted to address the deteriorating finances of India's electricity distribution companies (DISCOMs). Despite sustained interventions by central and state governments, financial losses continue to grow substantially, undermining these utilities' capacity to deliver reliable, quality power supply to consumers. Policy-makers at both central and state levels are currently contemplating another comprehensive financial restructuring effort (PIB, 2025). This effort has the potential to be fundamentally different from previous attempts, if it strongly considers two recent developments in the sector:

— First, cost competitive renewables and storage now offer viable pathways to reduce power procurement costs for DISCOMs and consumers while providing reliable supply. This addresses a primary challenge that remained unresolved in earlier reform cycles;
— Second, substantial investments over the past two decades in network infrastructure, supply reliability, and electricity market development have created the foundational conditions necessary for deeper structural reforms and business model transformation that were simply not feasible even a decade ago.

This report, examines the financial status of DISCOMs in India and discusses how these large public enterprises can strategically leverage emerging technological capabilities and evolving market conditions to restructure their operations and prevent the accumulation of future losses.This study details recent sector developments, particularly those following the launch of the *Ujwal DISCOM Assurance Yojana* (UDAY) in 2016 and the series of policy and techno-economic transformations that have reshaped the distribution business since 2020.

Like power sectors globally, India's power system stands at a critical juncture, propelled by four converging forces: the accelerating integration of renewable energy sources, rising household incomes and evolving consumer expectations, growing enterprise demand for reliable clean power, and the emergence of increasingly cost-competitive energy storage solutions. These interconnected trends are rapidly reconfiguring the operational and strategic landscape of India's future electricity grid. This analysis would remain incomplete if it did not focus on the implications of these trends and examined only the well-established challenges facing the power sector —power procurement cost escalation, subsidy dependence, Aggregate Technical and Commercial (AT&C) losses, and DISCOM debt sustainability.

Although evidence is still emerging regarding rapidly developing techno-economic trends, especially the availability of cost-competitive renewables and storage, they possess the potential to reshape India's electricity sector rapidly and profoundly—with or without policy intervention. The role of policy frameworks and institutional support becomes crucial in ensuring that these transformations unfold in an orderly manner and that DISCOMs, which remain central to providing reliable network and supply services, receive the necessary technical, institutional, and financial support to evolve alongside the rapidly changing sector.

Because DISCOMs play a crucial role in the power sector value chain, a report on DISCOM finances is essentially a study of the financial health of the power sector itself, which serves as crucial backbone infrastructure for the country's economic growth and development. The financial distress of DISCOMs has broader macroeconomic implications, affecting investment flows, the fiscal health of state governments, and the overall stability of India's energy security framework. Therefore, the analysis and recommendations of this study should be seen in the context of ensuring the stability of fundamental infrastructure services rather than solely from the perspective of DISCOM finances.

Against this backdrop, the study covers the financial challenges confronting India's electricity distribution companies (DISCOMs), with particular emphasis on their ongoing viability concerns. The analysis traces the evolution of legacy losses, identifies the primary drivers of current financial distress, and examines emerging trends that pose additional challenges to DISCOMs' traditional business models. Recognizing both the persistence of established problems and the emerging challenges, the final chapter synthesizes these findings to provide recommendations for addressing accumulated losses and liabilities, preventing future loss accumulation, and mitigating potential risk factors that could undermine DISCOM financial sustainability.

The analysis and assessment in this study is based on publicly available information as well as statutory reporting by Central Government Agencies, State Governments, Electricity Regulatory Commissions and DISCOMs in India. In addition, the authors referred to APTEL and Supreme Court judgements, as well as central and state government policies and rules. The data analysis was also supplemented with analysis and findings from the existing literature and through queries raised with state-level agencies.

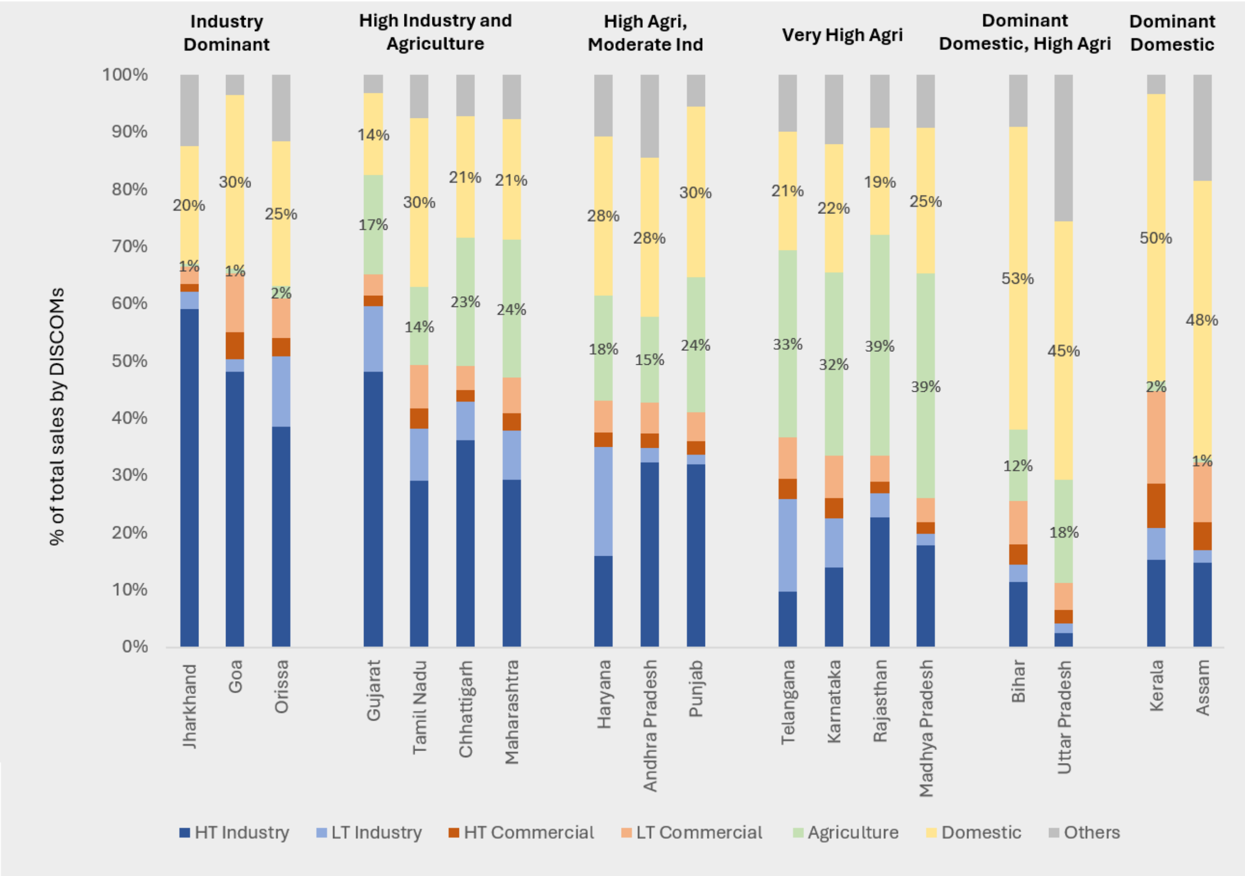
2 Overview of the power sector

This chapter provides a broad overview of India's power sector, establishing the necessary context for understanding the challenges and key developments confronting DISCOMs. It examines key trends related to electricity demand, supply, network infrastructure and institutional frameworks.

2.1 Electricity demand

Consistent with GDP growth trends, electricity demand has grown at a robust rate of approximately 6.5% annually between FY04 and FY23. At the national level in FY23, DISCOM sales were distributed across consumer categories as follows: 28% to residential consumers, 19% to agricultural consumers, and 42% to High Tension (HT) and Low Tension (LT) Commercial and Industrial (C&I) categories (CEA, 2024a).HT Industrial consumers account for more than half of the combined HT and LT C&I sales. Notably, the DISCOM sales mix varies significantly across states, as illustrated in Figure 1.

Figure 1:DISCOM sales mix across states



Source: Based on data in (CEA, 2024a) and information compiled from true-up orders for FY23.
Note: The 'Others' category includes public services, public water works, electric traction, streetlights, etc.

In Jharkhand, Goa and Odisha, the majority of sales was to industrial consumers in FY23. This was also the case in Gujarat, but the state also had substantial agricultural sales, at 17%. Tamil Nadu, Chhattisgarh and Maharashtra were similar to Gujarat in that respect, with substantial industrial as well as agricultural sales. In Telangana, Karnataka, Madhya Pradesh and Rajasthan, agricultural sales dominated, accounting for 30% to 40% of the total sales. Such high shares of agricultural consumption carry substantial implications for energy accounting and subsidy provisions. In Bihar, Uttar Pradesh, Kerala and Assam, residential sales were dominant. Bihar, Uttar Pradesh and Assam experienced significant growth in residential sales due electrification efforts since 2011. Kerala faces a distinct challenge, as residential consumers represent half the state's demand, making evening peak demand management particularly difficult due to concentrated appliance usage patterns.

Another crucial feature is that DISCOM demand has not been equivalent to state demand. This is mostly due to non-DISCOM procurement by consumers in the state. In fact, on average, at the national level about 12% of total sales and 30% of Industrial sales are from non-DISCOM sources (CEA, 2022). [34]

2.2 Electricity supply

Supply too has almost doubled every decade since 2004 and is projected to further double between FY24 and FY32. The crucial distinction between past and future supply growth is that in the past, capacity and generation growth was dominated by increased coal thermal capacity. However, future growth is expected to be driven by renewable energy. The share of renewable energy (including large hydro) in generation is expected to increase from the 22% in FY25 to 44% of generation by 2032 at the national level (CEA, 2025; CEA, 2023b). Storage is also estimated to play a key role in addressing reliability and variability concerns, with storage projected to account for 8% of the total capacity by 2032. In fact, to meet the growing demand, the National Electricity Plan, 2023 estimates an investment requirement of ₹27.9 lakh crore by FY32 towards deployment of renewables and storage (CEA, 2023b).

Between 2006 and 2024, 63% of capacity addition in the sector was due to the participation of the private sector. For coal thermal power, 48% of capacity addition of 150 GW came through private sector investments, while for renewables (excluding large hydro), 99% of capacity addition of 156 GW was through private investments (CEA, 2007; CEA, 2024). This trend is likely to continue in the future.

Privately owned capacity was contracted by DISCOMs primarily through competitive bidding. Significant tariff reductions have been achieved since the introduction of competitive bidding, particularly in wind and solar projects. Solar tariffs fell dramatically from ₹15/kWh in the initial bidding rounds of 2010 to ₹2.80/kWh by 2018. Similarly, for wind power, the introduction of competitive bidding in 2017 led to tariff reductions, with tariffs falling from ₹3.46/kWh to ₹2.50/kWh within a single fiscal year. While subsequent variation in prices have occurred due to modifications in taxation regimes, national policy frameworks, and global supply chain disruptions, the rapid price reduction within this compressed timeframe demonstrates the effectiveness of competitive bidding in facilitating efficient price discovery.

There is significant variation in states in terms of contracted capacity, which affects power procurement cost and power supply quality. Chhattisgarh, Bihar, Uttar Pradesh and Jharkhand are dominant in coal, whereas Andhra Pradesh, Karnataka and Tamil Nadu are dominant in solar and wind capacity. States such as Uttarakhand, Himachal and Meghalaya depend heavily on hydro sources, whereas Assam has a relatively high reliance on high-cost gas capacity.

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[34] This is as per data reported by CEA in the General Review on Utility and Non-Utility Sales for FY23 (CEA, 2024a). Data on captive and open access consumption is not captured in a disaggregated manner at the national level, and very few states offer disaggregated information, especially on on-site and off-site captive, group captive, etc. Estimates in DISCOM filings before state regulatory commissions in some state offer more details, which are captured in Section 6.4.

These state-level variations in power procurement and their impact on DISCOM costs and finances are explored in greater detail in Chapter 2 and the related annexures.

2.3 Network

As of FY23, about 62,06,549 circuit kilometres (ct. km) of extra high voltage (EHV) and high voltage (HV) lines were operating in India along with 82,17, 090 ct. km of low voltage (LV) lines. Six states, namely, Rajasthan, Madhya Pradesh, Gujarat, Uttar Pradesh, Karnataka and Maharashtra, accounted for 56% of the Transmission and High Tension Distribution (EHV and HV) lines in India.[35] In the case of Low tension distribution lines, six states accounted for 51% of the lines.[36]

Between FY04 and FY14, EHV and HV lines increased by 55% and LV lines by 46%. Similarly, between FY14 and FY23, EHV and HV lines increased by 47% and LV lines by 56%.

In the past, significant network investment, especially in LV lines, was channelled through government grants and consumer contributions. As on FY24, the outstanding grants and consumer contribution received for capital works totalled ₹1.98 lakh crore for state-owned distribution companies, which is as high as half the equity reported in FY24 (PFC, 2025).

The National Electricity Plan estimates an expected investment of ₹17 lakh crore in the sector between FY22 and FY32 (CEA, 2023b), with 54% allocated to transmission networks and the rest to distribution. There is substantial potential for this to be driven by private investment, especially in the transmission sector, given the introduction and implementation of tariff-based competitive bidding for the completion of specific lines and capital works with estimated project cost above a pre-defined threshold. Currently, 18 states have notified the capital investment threshold limit, above which competitive bidding must be initiated for a project. The cost threshold varies from ₹50 crore to ₹400 crore (PEG, 2025).

2.4 Institutions

India's electricity sector is governed by the Electricity Act, 2003, under which both the central government and state governments share concurrent jurisdiction. Each level of government plays important, unique, and complementary roles in the sector.

Central sector agencies are best positioned to provide a guiding and enabling framework that offers clear directional certainty while fostering cross-learning and innovation among states. Additionally, the central government plays a unique role in areas such as developing integrated markets, expanding inter-state networks, and establishing frameworks for power sharing between states.

State-level agencies, especially State Electricity Regulatory Commissions (SERCs), manage crucial aspects of the electricity sector, including tariff determination, licensing of distribution companies, and regulating intra-state transmission. State governments play a critical role in implementing state-level electricity and renewable energy policies, managing subsidies, and

[35] This is as per CEA data for the year FY23. Rajasthan had the highest share at 13%, followed by Madhya Pradesh with 10% and Gujarat with 9%. Uttar Pradesh, Karnataka and Maharashtra each accounted for 8% of the total network. Such high concentrations are perhaps due to not just significant demand but also generation capacity in these states.

[36] Uttar Pradesh had the highest share of LV/LT lines at 14%, followed by Maharashtra with 9%, Tamil Nadu with 8%, Rajasthan and Bihar with 7% and Madhya Pradesh with 6%. Capital investments in networks are influenced by several factors, and without a detailed study, it is difficult to ascribe clear reasons for these numbers.

launching state-specific schemes to aid sector development. This structure allows states to experiment with innovative solutions, pilot new technologies, and adapt policies to their specific contexts.

As of March 31, 2023, 151 companies under central, state or joint partnership were engaged in generation, transmission, and distribution. This excludes 11 electricity departments in states and union territories. Additionally, 113 private generating companies and 11 privately owned transmission companies were in operation (CEA, 2024a).

India has 30 State Electricity Regulatory Commissions (SERCs) for states and union territories, as well as a Central Electricity Regulatory Commission (CERC). SERCs are responsible for licensing of DISCOMs and state transmission companies, tariff determination, frameworks for open access and captive operationalization, state grid codes, etc. The Central Commission approves and adjudicates inter-state contracts, provides the regulatory framework for inter-state traders and power exchanges, grants licenses to inter-state transmission companies, and is responsible for performance accountability of cost-plus generating companies with nation-wide operations. Appeals against all commission orders are heard by the Appellate Tribunal for Electricity.

State Load Dispatch Centres (SLDCs) coordinate the minute-by-minute operation of the power system at the state level, working in conjunction with Regional and National Load Dispatch Centres, which operate the national grid.

Power sector planning occurs at both the national and state levels, with DISCOMs, SERCs, state transmission companies, SLDCs, and state governments playing crucial roles. National-level plans, ideally based on state-level plans, are prepared by the Central Electricity Authority (CEA), which is also responsible for preparing safety standards, metering regulations, and ensuring data submission by various power sector agencies.

The sector is supported by two NBFCs—the Power Finance Corporation (PFC) and the Rural Electrification Corporation (REC)—which operate under the administrative control of the Ministry of Power (MoP) to finance crucial projects in the sector.

Three power exchanges—India Energy Exchange, Power Exchange India Limited and Hindustan Power exchange—offer real-time, day ahead and term ahead contracts. In addition, inter-state and intra-state trading licensees facilitate bilateral contracts, and OTC platforms provide information on bilateral trading options in the market.

Key Takeaways

— India's power sector is undergoing a fundamental transition from coal-dominated to renewable energy-driven growth, with the share of renewables expected to double from 22% in FY24 to 44% by 2032. This transition will be driven by investments of ₹27.9 lakh crore in renewables and storage technology. Most of this investment is expected to come from the private sector.
— Electricity demand is expected to keep pace with GDP growth. However, 12% of total sales and 30% of industrial sales relied on non-DISCOM sources for power supply at the national level in FY24. In the future as well, not all sector demand is going to be met through DISCOM sources; open access and captive sources will play a more significant role.
— There is substantial variation in category-wise demand across states, which influences the extent of peak demand, subsidy requirement, quality of metering and energy accounting as well as the demand for reliable services.
— India's electricity sector has been seeing substantial investments in both HT and LT networks in the past two decades, which has improved grid access and reliability. However, capital expenditure is reliant on consumer contributions and grants, with such funding touching approximately ₹1.98 lakh crores. Between 2022 and 2032, about ₹17 lakh crore investment is expected in the transmission and distribution businesses. Measures such as competitive bidding for transmission can help with timely completion and cost reduction.
— The electricity sector is a concurrent subject, with multiple agencies at the national and state levels playing crucial roles as planners, regulators and service providers. The role of central agencies is to provide frameworks and technical support to ensure coordinated, integrated development across the country to foster state-level developments and cross-learning. However, the state-level power sector is governed by the state government and its agencies. SERCs and DISCOMs play crucial roles in shaping the future of state-level power sectors.

3 Understanding past and ongoing schemes to address financial losses of DISCOMs

The accumulated losses of state-owned DISCOMs in India are reported to have reached ₹7.08 lakh crore by the end of FY24, rising at an annual growth rate of 8.23% since FY17 (PFC, 2025; PFC, 2020). To manage these growing losses, DISCOMs borrow heavily to manage day-to-day operations, resulting in a build-up of liabilities. To address these liabilities, several debt restructuring schemes have been launched in the past. These schemes addressed cumulative liabilities and incorporate conditionalities and frameworks to improve the performance and financial viability of DISCOMs. However, despite these efforts, DISCOMs still face severe financial challenges. This chapter describes the broad framework of these schemes and its implementation status.

3.1 Past schemes to address financial challenges of DISCOMs until UDAY

This build-up of losses and liabilities has occurred despite multiple schemes and efforts by the central and state governments to restructure and take over the losses and debt of these DISCOMs. These efforts are detailed below.

3.1.1 Payment of dues to central sector utilities via Central Plan Assistance

Until 1996, the central government would deduct amounts from the Central Plan Assistance (CPA) of the states in lieu of repayment of dues to central sector utilities. Four such deductions had been made until December 1996. The outstanding dues by this time were so significant that with 15% deduction from the annual CPA, the deductions were to continue for 4 to 27 years in different states. With the growth in dues, this method became ineffective (Planning Commission, 2001).

3.1.2 Settlement of SEB Dues Scheme

Given the increase in dues, in 2002, based on the recommendations of the Expert Group on Power Sector Reforms, the central government launched a scheme for state governments to take over the outstanding dues to Central Power Sector Undertakings (CPSUs). By 2002, the outstanding dues to CPSUs stood at ₹41,473 crore. Along with Delhi, seven states Bihar, Uttar Pradesh, Madhya Pradesh, West Bengal, Gujarat, Haryana and Maharashtra—were responsible for 74% of the total dues. Bihar, Uttar Pradesh and the erstwhile Delhi Vidyut Board accounted for about 40% of the liabilities (Planning Commission, 2001). For more details, see Table 36 in Annexure 1. Under the scheme, 50% of the interest expenses on delayed payments was waived and the rest of the amount was taken over and securitised as bonds by the state governments. The bonds were issued as 15-year tax-free bonds with a five-year moratorium on the principal. There were lock-in restrictions, with only 10% of the amount taken over released on the secondary market each year. In turn, the electricity boards had to commit to performance milestones related to metering, energy auditing and elimination of revenue gaps. To incentivise good practices, in case of timely payment to generators, incentives equivalent to 2% of the value of bonds were to be provided to the electricity board.

3.1.3 Transfer scheme while unbundling SEBs as mandated under Electricity Act, 2003

According to Section 131 of the Electricity Act, the outstanding liabilities of state electricity boards should be transferred to the state government, ensuring that the newly unbundled entities are unencumbered by past financial obligations (MoLJ, 2003). Although several states have unbundled their vertically integrated electricity boards into multiple corporations, only a few have assumed these liabilities. Gujarat, where the DISCOMs are financially healthy, is a notable exception where the liabilities have been taken over.

3.1.4 Financial Restructuring Plan (FRP)

By 31 March 2011, the liabilities of DISCOMs had shot up to ₹1.9 lakh crore (PIB, 2012). Seven states accounted for 63% of these liabilities: Uttar Pradesh, Madhya Pradesh, Haryana, Rajasthan, Tamil Nadu, Punjab, and Andhra Pradesh. The first three were major contributors during the earlier SEB Bailout scheme as well. Among the latter four, Rajasthan and Tamil Nadu alone represented 31% of total liabilities (see Table 37, Annexure 1).

To address this, in October 2012, the Financial Restructuring Plan was launched. Whereas the 2001 scheme for SEBs described above was designed to take over DISCOM dues to CPSUs, the FRP focused on working capital borrowing from scheduled commercial banks, which formed the bulk of the liabilities. As per the scheme:

— Half of the outstanding liabilities were to be taken over by the state government, converted to bonds in a 2–5 year time frame and issued in favour of participating lenders backed by state government guarantees.
— The other half of the outstanding liabilities was to be serviced by DISCOMs. However, repayment was rescheduled with favourable interest terms, the interest and principal being backed by a state government guarantee.

The takeover was contingent upon compliance with conditions to improve operational performance (e.g., AT&C loss reduction, regular tariff revision, time-bound liquidation of regulatory assets, avoidance of short-term loans and agricultural subsidies based on feeder metering data.).

The central government also provided transitional finance support, including the following:

— Incentives for accelerated AT&C loss reduction (for eligible DISCOMs which also demonstrate a reduction in revenue gaps)
— Reimbursement of 25% of principal payments of bonds in case of full debt takeover

3.2 Experience with the UDAY scheme

The central government launched UDAY in November 2015. UDAY followed a similar approach to that of FRP. The scheme aimed to resolve DISCOMs' outstanding liabilities from short-term and working capital borrowings. State governments took over this debt by issuing government bonds. In turn, state governments had the option to assume DISCOM liabilities from DISCOMs through three primary financial instruments, grants, equity or debt. Grants and equity provided direct financial relief without repayment obligations for the DISCOMs whereas loans modified existing debt terms with more favourable repayment conditions, resulting in only interest cost savings.[37]

All bonds issued under FRP were to be subsumed under UDAY. UDAY bonds themselves were privately placed, with issuance to REC, PFC and pension/insurance companies. The central

[37] The scheme itself prescribed takeover via conversion to grant. However, for state governments facing significant fiscal impact with the takeover, the transfer could as debt, which get converted to grants in a phased manner. In exceptional cases, 25% of the amount could be transferred as equity as opposed to transfer as grants.

government provided a special dispensation amounting to ₹9,571 crore to Jharkhand and Jammu & Kashmir to clear their dues to CPSUs.

Participating states which met operational milestones would be prioritised for power and coal allocation, as well as for central sector capital investment schemes. Operational milestones pertained to network and consumer metering, AT&C loss reduction, revenue gap reduction, implementation of fuel adjustment charges, etc. An additional important condition of UDAY was the limit on working capital borrowing to 25% of the annual revenue of the previous year (MoP, 2015).

All participating states signed MoUs with specific terms for takeover as well as commitments towards operational milestones, which are broadly aligned with the scheme contours detailed in this section. The debt identified for takeover (including takeover under FRP) was about ₹3.56 lakh crore across 16 participating states. Five states, namely Rajasthan, Uttar Pradesh, Madhya Pradesh, Haryana and Tamil Nadu, accounted for 81% of the identified liabilities.

A distinctive feature of the UDAY scheme required state governments to commit to taking over future DISCOM losses through a graduated mechanism. Under this arrangement which is also referred to as annual loss funding, state governments would take over 5% of the previous year's losses in FY17, with this percentage increasing annually to at least reach 50% by FY21.

3.2.1 Takeover of outstanding liabilities under UDAY

State governments had committed to take over 75% of the outstanding liabilities in FY16. Some states that undertook debt takeover as committed under UDAY experienced measurable financial benefits. In Rajasthan and Haryana, complete liability takeover substantially reduced interest cost burdens and annual expenses, effectively arresting the growth of accumulated losses. However, some states only partially implemented the debt takeover provisions. Madhya Pradesh completed takeover of 37% of the identified liabilities, whereas Tamil Nadu addressed only 34%, which represents a significant shortfall. Telangana and Jharkhand also experienced shortfalls in debt takeover (Table 1). The continuing interest burden on non-transferred debt has contributed to the ongoing loss accumulation in these states.

As discussed in Section 3.2, liabilities taken over by the state government can be in the form of grants, equity or restructuring of DISCOM loans. When takeover is in the form of debt rather than grant or equity, the liabilities decrease only due to restructured interest rates. In most states, the takeover was either through grant or equity. However, in Jharkhand, Chhattisgarh and Himachal Pradesh, the majority of the takeover was transferred as debt. In Uttar Pradesh and Haryana, about 15% of the takeover was through debt (Table 1).

Table 1: Actual takeover of outstanding liabilities under UDAY

State	Total outstanding debt (as per MOU)	Debt takeover (as per MOU)	Actual debt takeover	Actual debt takeover as % of outstanding debt	Share of actual debt takeover transferred as		
					Equity	Loan	Grant
	₹ Cr.	₹ Cr.	₹ Cr.	%	%	%	%
Maharashtra	6,613	4,960	4,960	75%	0%	0%	100%
Bihar	3,109	2,332	2,332	75%	0%	0%	100%
Andhra Pradesh	11,008	8,892	8,256	75%	0%	0%	100%
Assam	1,510	1,133	1,133	75%	25%	0%	75%
Meghalaya	167	125	125	75%	25%	0%	75%
Rajasthan	83,230	62,423	62,422	75%	25%	0%	75%
Tamil Nadu	75,089	25,815	25,815	**34%**	0%	0%	100%
Uttar Pradesh	59,205	44,403	44,403	75%	34%	**22%**	44%
Madhya Pradesh	34,739	26,055	12,690	**37%**	60%	0%	40%
Jharkhand	9,233	6,925	6,136	**66%**	0%	**90%**	10%
Chhattisgarh	1,154	865	870	75%	0%	**100%**	0%
Haryana	34,600	25,950	25,950	75%	80%	**20%**	0%
Himachal Pradesh	3,854	2,891	2,891	75%	0%	**100%**	0%
Punjab	20,838	15,628	15,628	75%	100%	0%	0%
Telangana	11,897	8,923	7,723	**65%**	100%	0%	0%

Source: CAG reports on UDAY implementation, CAG Audit Reports on State Finance from FY17 to FY23.

3.2.2 Annual loss funding under UDAY

CAG state finance audit reports for FY17–FY23 indicate that state governments in seven states undertook annual loss funding after 2016 as stipulated under UDAY (see Table 2).

Table 2: Annual loss takeover under UDAY until FY23

Total annual loss takeover under UDAY until FY23		
State	Total annual loss takeover reported under UDAY	Total loss takeover under UDAY as a % of total losses
	₹ Cr.	% of total losses in period
Tamil Nadu	9,366	12%
Telangana	7,061	18%
Uttar Pradesh	5,771	15%
Madhya Pradesh	3,795	19%
Punjab	821	16%
Meghalaya	13	1%
Haryana	10	Unclear

Notes:
- Haryana DISCOMs did not report losses between FY16 and FY21.
- The figures are taken from the latest available reports for each year of reporting.
- Uttar Pradesh reporting is from the state finance audit report and is not on OFR (Operational Funding Requirement) basis as published in the CAG UDAY performance audit report.

Source: CAG reports on UDAY implementation, CAG Audit Reports on State Finance from FY17 to FY23.

Excluding Haryana and Meghalaya, loss takeover rates during this period ranged from 12% to 19% of the total losses. Whereas Madhya Pradesh achieved the highest takeover rate in percentage terms, Tamil Nadu recorded the largest absolute quantum. Despite that, the quantum of takeover is not substantial in comparison to the outstanding debt and build-up of losses. Although the scheme envisaged a phased takeover of 50% of losses by FY21, only ₹26,837 crore was taken over in seven states, which is 15% of the losses on average for the period FY17–FY23.

3.3 Post-UDAY initiatives to address the financial challenges of the power sector

Following UDAY's implementation, the central government launched several complementary initiatives to address the persistent financial losses of DISCOMs and the broader build-up of liabilities across the power sector value chain. These measures are outlined below.

3.3.1 Liquidity Infusion Scheme (LIS)

In May 2020, the government introduced the Liquidity Infusion Scheme (LIS) to address DISCOMs' cash flow challenges arising from the COVID-19 lockdowns. Under this scheme, REC and PFC extended loans backed by state government guarantees to enable DISCOMs to make timely payments.

These loans, known as special long-term transition loans (STTLs), had tenures of up to 10 years and interest rates of approximately 9.5–10%. They were restricted to clearing outstanding dues to generators and transmission companies. By December 2021, PFC and REC had disbursed ₹1.2 lakh crore, representing 16% of total national DISCOM borrowings (PIB, 2023). Disbursement patterns varied significantly across states, as detailed in Table 3. Four states—Uttar Pradesh, Tamil Nadu, Telangana and Rajasthan—received the majority of LIS funding. The scheme's relative importance differed markedly by state: LIS loans constituted nearly 50% of total DISCOM borrowings in Uttar Pradesh and approximately one-third in Telangana. In contrast, Maharashtra DISCOMs utilised LIS funding for only 3% of their total borrowings.

3.3.2 Late Payment Surcharge (LPS) Rules

In June 2022, the Ministry of Power notified the Late Payment Surcharge (LPS) Rules, marking a significant policy intervention to enforce payment discipline among DISCOMs. The rules introduced stringent penalties, including reduced access to inter-state transmission networks in case DISCOMs fail to clear dues within one month of the due date.

For outstanding dues existing as of June 2022, DISCOMs were required to adhere to a graduated liquidation schedule: dues below ₹500 crore were to be cleared within 12 months, while obligations exceeding ₹10,000 crore were permitted a 48-month clearance period. Non-compliance with these schedules would also trigger network access restrictions, effectively constraining DISCOMs' power supply capabilities (MoP, 2022). The enforcement mechanism resulted in substantial improvements in payment behaviour. Outstanding dues to private and central sector utilities declined dramatically from ₹1,39,947 crore in June 2022 to ₹14,251 crore by May 2025 (PIB, 2024; MoP, 2025).

Assuming that 100% of outstanding dues as of June 2022 under LPS is addressed by DISCOMS through borrowing, the order of magnitude share of borrowing for LPS and LIS is detailed is also represented in Table 3[38]. As shown in Table 3, LPS and LIS borrowings could account for about

[38] Against legacy dues of ₹1,39,947 Cr as of June 2022, 13 States opted for a graduated liquidation schedule, and ten of these states secured loans from PFC/ REC to finance payments (MoP, 2024). The loans disbursed by PFC/ REC

₹2.52 lakh crore, constituting 36% of total outstanding DISCOM debt in FY24. Six states—Tamil Nadu, Uttar Pradesh, Rajasthan, Andhra Pradesh, Telangana and Maharashtra—account for possibly 74% of the combined LPS and LIS borrowings.

Table 3: Contribution of LPS and LIS borrowings to total borrowing by DISCOMs

State	Total borrowing under LIS	LIS loans as % of total outstanding (o/s) borrowings	Total outstanding dues to be take over under LPS	LIS borrowings and LPS borrowings as share of total o/s borrowing
	₹ Cr.	%	₹ Cr.	%
Tamil Nadu	26,797	15%	17,734	26%
Uttar Pradesh	32,840	48%	6,762	58%
Rajasthan	11,566	13%	22,234	37%
Andhra Pradesh	8,308	13%	18,310	41%
Jammu & Kashmir	10,322	Not available	14,164	Not available
Telangana	12,576	27%	9,950	49%
Maharashtra	2,500	3%	17,320	23%
Karnataka	0	0%	13,558	34%
Madhya Pradesh	0	0%	8,500	17%
Jharkhand	0	0%	6,000	32%
Bihar	3,492	25%	1,092	33%
Chhattisgarh	0	0%	4,162	77%
Meghalaya	1,102	67%	0	67%
Punjab	1,000	5%	0	5%
West Bengal	940	6%	0	6%
Uttarakhand	600	31%	0	31%
Himachal Pradesh	276	4%	0	4%
Manipur	112	15%	161	37%
Total	**1,12,431**	**16%**	**1,39,947**	**36%**

Source: Compiled by authors from (PIB, 2023a; PFC, 2025; PIB, 2023b; LS, 2024)

As mentioned earlier, UDAY stipulated that working capital borrowing be less than 25% of DISCOM revenue. In 2022, PFC notified additional prudential norms which considered a higher working capital borrowing limit at 35% of revenue. However, long-tenure loans extended under LPS and LIS were classified as additional to this 35% ceiling (MoP, 2022).Thus, additional borrowing under LPS and LIS would be provided by PFC even if total working capital borrowing is higher than 35%.

3.3.3 Additional borrowing limit conditional on power sector performance

In June 2021, the Ministry of Finance implemented the 15th Finance Commission's recommendation to permit additional borrowing by states of up to 0.5% of GSDP annually from FY22 to FY25. This enhanced borrowing space is contingent upon states and DISCOMs meeting specific power sector reform conditions, with compliance monitored by the MoP. By June 2022, 12 state governments had qualified for additional borrowing totalling ₹39,175 crore, while seven states received approval for ₹33,013 crore in FY23 (PIB, 2024).

To qualify for additional borrowing under this framework, state governments were required to undertake two mandatory actions:

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alone were to the tune of ₹1,13,737 Cr amounting to 81% of the total dues. While state-wise details of disbursements are not available in a disaggregated manner, it is clear that bulk of the dues were settled through loans.

Annual loss takeover: All losses incurred in a year were to be taken over by the state government in a progressive manner similar to the loss funding provision under UDAY.

Improvements in financial reporting: These included transparency in reporting subsidy payments and recording liabilities, timely provision of financial and energy audits, etc.

In addition, to determine the extent of relaxation in borrowing limit to be provided, the states' performance was evaluated on the following parameters:

— Status of consumer metering
— Implementation of Direct Benefit Transfer for subsidy payments
— Achievement of AT&C loss reduction targets
— Reduction in revenue gaps and cross-subsidies
— Timely payment of electricity bills by government departments coupled with pre-paid metering in government offices

States were also eligible for additional credit in case privatisation of distribution companies was undertaken in this period.

Annual loss takeover by states totalled ₹23,200 crore in FY22 and ₹43,600 crore in FY23. In FY23, loss takeover was reported by Tamil Nadu, Telangana, Andhra Pradesh, Bihar, Rajasthan and Uttar Pradesh. In the following year (FY24), Andhra Pradesh, Uttar Pradesh, Rajasthan, Telangana, and Tamil Nadu continued this practice. In FY22, the Tamil Nadu government took over ₹11,954 crore, followed by ₹17,117 crore in FY23 and ₹19,090 crore in FY24. This accounts for 60% to 75% of the annual losses of the DISCOM in this period. In fact, the Tamil Nadu state government assumed 52% of the overall national takeover in FY22 and 39% in FY23.

There was also significant improvement in financial reporting in some states. For example, the annual audited financial statements/reports of DISCOMs in the states listed below provided the following details, complying with the scheme conditions:

— Clear reporting of working capital borrowing was observed in five states: Andhra Pradesh, Telangana, Haryana, Bihar and Maharashtra.
— Details of government guarantees to loans taken were provided in Andhra Pradesh, Maharashtra, Telangana, Tamil Nadu, Rajasthan, Uttar Pradesh, Haryana, Bihar and Punjab.
— Age-wise receivables were available in Uttar Pradesh, Telangana, Maharashtra, Karnataka, Andhra Pradesh, Rajasthan, Tamil Nadu, Haryana, Bihar and Punjab.
— Clear reporting of subsidy payments was provided in Andhra Pradesh, Maharashtra, Telangana, Tamil Nadu, Rajasthan, Uttar Pradesh, Bihar and Punjab.
— Clear reporting on pending dues by state governments was seen in Andhra Pradesh, Madhya Pradesh, Maharashtra, Rajasthan, Tamil Nadu, Telangana, Haryana and Bihar.

3.3.4 Revamped Distribution Sector Scheme (RDSS)

In July 2021, the MoP launched RDSS, which primarily focused on smart metering and network investment. The scheme made available over ₹90,000 crore in grants for system-strengthening measures targeting agricultural solarisation, distribution network reliability enhancement and loss reduction (MoP, 2021). RDSS incorporated stringent eligibility and performance criteria that complemented the conditions stipulated for additional borrowing limit relaxation described earlier.

The eligibility criteria for the grants include the following:

— Publishing quarterly and annual accounts in a timely manner
— Not creating new regulatory assets
— Paying subsidies and clearing subsidy arrears in a timely fashion
— Timely payment of bills by government departments and public bodies along with clearing arrears as well as progress with pre-paid metering in government offices
— Making progress in reducing payables to generators in line with pre-stipulated criteria
— Issuing tariff order and true-up orders in a timely fashion

Further, the performance of the DISCOMs was evaluated on financial criteria such as AT&C loss reduction, reduction in revenue gaps, liquidation of existing regulatory assets, improvements in receivables from consumers and payables to generators, and reduction in outstanding subsidy payments and government dues in electricity bills.

The combined framework of conditional enhanced borrowing limits and performance-linked RDSS grants has provided structured incentives for DISCOMs to improve operational performance and financial viability. Preliminary evidence suggests improvements in specific areas, including timely subsidy payments, settlement of government dues and reporting of financial information, as detailed in the Chapter 4. Where states have implemented the prescribed measures, the rate of growth of accumulation of losses has decelerated to some extent.

Key Takeaways

— DISCOM financial challenges have persisted despite multiple bailout schemes. However, evidence from Rajasthan, Haryana and Gujarat demonstrates that where complete takeover of past liabilities has been undertaken, growth in future losses is arrested. This is important for Madhya Pradesh and Tamil Nadu, where legacy losses are still affecting current financial viability.

— By FY24, state-owned DISCOMs had accumulated losses of ₹7.08 lakh crore. This build-up occurred after the implementation of UDAY and the annual loss takeover by DISCOMs as per conditionalities to obtain increased additional borrowing limits recommended by the 15th Finance Commission and under the RDSS scheme.

— Despite financial distress, private and central sector generation and transmission companies experienced timely payment of dues with the implementation of liquidity infusion schemes and late payment surcharge rules. Under these schemes, to enable clearance of pending dues, states have taken long-term working capital loans of approximately ₹2.5 lakh crore, accounting for 36% of the total DISCOM borrowings at the national level. However, payables to state-owned generators and transmission companies remain substantial, indicating ongoing DISCOM cash flow challenges.

Recommendations:

- Addressing legacy losses and liabilities of DISCOMs is critical to improve existing financial position and prevent build-up of future liabilities. Given the existing losses, state government should prioritise take-over of liabilities of DISCOMs which can be enabled by the central government scheme on the lines of UDAY. However, strict conditionalities, which can be state-specific are required to prevent build-up of future losses.
- Timely payment of subsidies and state government dues as well as improved reporting of key financial statistics have taken place due to initiatives such as RDSS and conditions to avail additional borrowing limit. Incentives and frameworks to ensure such payment and reporting discipline continues are crucial.
- While LPS and LIS have ensured financial viability of private and state-owned generating and transmission companies, working capital borrowing of DISCOMs are affected which need to be addressed to prevent rising interest cost burden on DISCOMs.

4 Major contributors to the post-UDAY build-up of losses

Despite the UDAY initiative, accumulated DISCOM financial losses have continued to grow at an average rate of 4% per annum in real terms between FY16 and FY24 at the national level. The average annual growth rate of losses for this period is 8.15% in nominal terms. As shown in Table 4, six states (Tamil Nadu, Rajasthan, Uttar Pradesh, Madhya Pradesh, Telangana and Maharashtra) accounted for 74% of the ₹7.08 lakh crore in accumulated losses recorded at the national level at the end of FY24. Kerala recorded the seventh highest losses in FY24. However, between FY19 and FY22, Andhra Pradesh was among the top seven states contributing to aggregate accumulated losses. Additionally, the number of states contributing more than 4% of national accumulated losses increased between FY16 and FY24, indicating a broadening of financial distress across the sector.

Table 4: Largest contributors to accumulated losses

% share in accumulated losses in FY16 and FY24			
Share of states in total accumulated losses	**FY16**	**Share of states in total accumulated losses**	**FY24**
Rajasthan	24%	Tamil Nadu	24%
Uttar Pradesh	18%	Rajasthan	13%
Tamil Nadu	17%	Uttar Pradesh	13%
Madhya Pradesh	9%	Madhya Pradesh	10%
Haryana	8%	Telangana	9%
Maharashtra	7%	Maharashtra	5%
Telangana	4%	Kerala	5%
Andhra Pradesh	4%	Andhra Pradesh	4%
Others	9%	Haryana	4%
		Karnataka	4%
		Others	10%

Source: (PFC, 2025; PFC, 2017)

Although the quantum of losses was the highest in these states, the growth of accumulated losses after UDAY varied across states between FY16 and FY24. In Maharashtra and Uttar Pradesh, growth of losses was not significant with compounded annual growth rates (CAGRs) at 4% for this period on nominal basis. Therefore, in real terms, the losses have not increased. In the case of Andhra Pradesh and Madhya Pradesh, the CAGR was 9% (nominal basis), closer to the national average for this period. However, in Tamil Nadu and Telangana, it was high: 13% and 19%, respectively. See Annexure 2 for more details.

Haryana and Rajasthan maintained accumulated losses at approximately FY16 levels in nominal terms. UDAY's debt takeover and consequent reduction in interest cost, combined with operational improvements, contributed to reduced annual expenses in both states. Haryana DISCOMs saw both a cost reduction[39] as well as a downward revision in revenue and

[39] Some of the reduction in cost in Haryana is attributable to the rapid reduction in distribution lines losses post-UDAY. Distribution line losses, which stood at 27% in FY16, dropped to 10% by FY23, demonstrating an annual average reduction of 2 percentage points. To understand the impact of such a substantial reduction, consider a scenario where losses had declined to only 20% by FY23, representing a one percentage point annual reduction. A one percentage point reduction would also be consistent with the loss reduction demonstrated by Haryana DISCOMs between FY04 and FY13. In such a case, DISCOMs would have incurred additional costs of ₹7,041 crore in FY23, resulting in 17% higher annual expenses. This reduction is reported to have been achieved through administrative measures and improvements in metering (Sharma, Balani, Agrawal, Bhattarai, & Singh, 2023).

state government subsidy, lowering the revenue gaps, whereas Rajasthan continued to experience revenue shortfalls, despite reduction in cost.

A striking fact which corroborates the broadening of financial distress observed in Table 4 is the alarmingly high growth in losses among other relatively smaller states. For example, between FY16 and FY24, the CAGR for accumulated losses was as high as 42% for Kerala, about 30% for Jharkhand, 20% for Manipur, Meghalaya and Bihar and 15% for Punjab. This is also detailed in Annexure 2.

A few states have reduced accumulated financial losses since UDAY's implementation (Annexure 2). Assam presents a particularly striking example, with accumulated losses declining dramatically from ₹3,089 crore in FY16 to ₹1,324 crore in FY23. This improvement stemmed primarily from complete liability takeover under UDAY and substantial state government support to meet annual revenue gaps. In FY24, such state support constituted 15% of total expenses—without this intervention, accumulated losses would have more than doubled from FY16 levels. Assam's DISCOM also demonstrated operational improvements, achieving an 8 percentage point reduction in AT&C losses between FY16 and FY18, with sustained reductions thereafter attributed to improved administrative practices and metering for revenue collection.

The reasons for loss accumulation vary from state to state. However, some of the main reasons are as follows:

- Issues with power procurement planning and pricing
- Lack of timely cost recovery due to delayed resolution of tariff-related matters before APTEL
- Inadequate and infrequent tariff increases
- Delay in revenue recovery and subsidy payments
- Build-up of interest cost and working capital liabilities

In this section, the reasons for loss build-up will be analysed with a focus on the seven states which have consistently been among the top contributors to accumulated losses nationally. These states are Uttar Pradesh, Rajasthan, Maharashtra, Telangana, Tamil Nadu, Madhya Pradesh and Andhra Pradesh.

4.1 Power procurement planning and pricing

Coal-based power plants supplied 70–80% of electricity procurement in Uttar Pradesh, Rajasthan and Maharashtra during FY24, maintaining a consistent trend over the past eight years. This significant dependence exposes DISCOMs to fuel price volatility and availability risks, directly impacting procurement costs. Purchase rates from coal-based sources in these states range from ₹4.5 to ₹5.0 per unit, with tariffs for new coal capacity approaching ₹6 per unit.

Madhya Pradesh demonstrates similar coal dependency at 77% but benefits from significantly lower costs of approximately ₹3.9 per unit because the majority of its coal generators are pit-head plants, which minimises transportation expenses.

Telangana, Tamil Nadu and Andhra Pradesh exhibit relatively lower coal dependence at approximately 65%. However, these states rely heavily on short-term market purchases (10% to 18% of total procurement), where prices are substantially higher. Coal-based power costs in these states range from ₹5.10 to ₹5.13 per unit, reflecting significant transportation costs, which constitute 40% to 50% of total coal expenses. State-wise, source-wise details of power procurement in 17 states are compiled in Annexure 3.

One of the major reasons for high cost procurement is poor planning. Because capacity, especially coal-based capacity, has long gestation periods, requires significant up-front investment and annual fixed payments, irrespective of generation, it is crucial that the decision to add capacity is based on a scientific assessment of demand and based on least cost planning principles. However, in these seven states, long-term demand and supply assessments were conducted on an ad hoc basis rather than periodically. These assessments were initiated to add specific capacity, not to identify the most cost-effective solutions to meet the demand (PEG, 2017; CEER, 2018; ETPI, 2023).

Between FY16 and FY25, a total of 36,241 MW of coal-based capacity was added in India. As much as 73% of this capacity was procured/contracted in the seven states, as shown in Table 5. The highest addition was in Telangana (17% of the total capacity added, 6028 MW) and Uttar Pradesh (26% of the total, 13068 MW). This addition itself increased annual expenses by ₹16,215 crore in Uttar Pradesh and by about ₹7,689 crore in Telangana due to fixed cost payments. Expenses in the seven states increased by 4% to 16% annually due to the cost increase associated with capacity addition alone. Thus, revenue would have to increase commensurately to prevent increase in revenue gaps or losses.

Table 5: Lumpy increase in cost due to coal-based capacity addition

State	Coal capacity added between FY16 and FY25	Annual fixed cost contribution to total costs	Annual fixed cost contribution as % of total expenses
	MW	₹ Cr.	FY24
Andhra Pradesh	5,037	3,008	4%
Maharashtra	4,595	5,488	4%
Madhya Pradesh	4,017	4,668	8%
Rajasthan	4,057	3,421	4%
Tamil Nadu	3,177	2,566	3%
Telangana	6,028	7,689	12%
Uttar Pradesh	13,068	16,215	16%

Source: Data compiled by authors from regulatory filings and orders.

When capacity is added through cost-plus route, rather than competitive bidding, there is a reduction in price efficiency. The majority of the capacity contracted in these seven states post UDAY was via the cost-plus route, either through state-owed or central sector generating stations, as shown in Table 6.

Table 6: Cost-plus capacity addition across states

State-owned DISCOMs in	Total capacity added between FY16 and FY25	% cost-plus of the total capacity added	% share of state-owned capacity to total capacity added	% share of central sector capacity to total capacity added	Average delay in cost-plus capacity addition
	MW	%	%	%	Months
Andhra Pradesh	5,037	71%	44%	7%	54
Maharashtra	4,595	100%	59%	41%	22
Madhya Pradesh	4,017	100%	33%	51%	14
Rajasthan	4,057	100%	81%	11%	29
Tamil Nadu	3,177	63%	0%	47%	83
Telangana	6,028	88%	54%	34%	40
Uttar Pradesh	13,068	74%	33%	26%	21

Source: Regulatory orders from various states.

In cost-plus projects, there are often delays and associated cost overruns. This is primarily because cost-plus contracts, unlike competitively bid contracts, lack strict provisions for timely commissioning. Among these seven states, the average delay for capacity addition from the expected timelines ranged from 4 months to 7 years for capacity from state-owned generators, 1to 4 years for the central sector and 2.4 to 9.5 years for privately owned cost-plus capacity. See Annexure 4 for more details.

Coal availability and fuel price volatility are also major contributors to cost increase. Between December 2021 and June 2024, various advisories and directions were issued under Section 11 of the Electricity Act by the central government for central sector, state-owned and private generators, requiring them to meet a pre-stipulated percentage of their coal supply requirements via imported coal. These directives were to address supply challenges with domestic coal, because the coal supply chain was unprepared for the post-pandemic uptick in demand. The pre-stipulated percentage varied from 4% between December 2021 and April 2022 to 10% between April and November 2022, with a reduction to about 6% between September 2023 to June 2024. See Annexure 5 for more details.

The increase in utilisation of imported coal at a time when international coal prices were high[40] resulted in a considerable increase in power purchase costs (PFC, 2024). According to one estimate, power purchase costs increased by 15% in FY23 compared to FY22, primarily due to coal shortages and imported coal utilisation (PFC, 2024).

Even with competitive bidding, fuel risk is present and is passed on to consumers. Between FY19 and FY22, Maharashtra State Electricity Distribution Company Limited (MSEDCL) settled ₹22,626 crore with private generators contracted via competitive bidding in lieu of 'change in law' claims for variation in energy charges given the shortfall in domestic coal (MSEDCL, 2022).

[40] On average, international coal prices were 131% higher between April 2022 and January 2023 than between April 2021 and January 2022. This was primarily due to disruptions in global coal supply chains related to the Russia–Ukraine conflict. The average cost of imported coal for India rose to over ₹12,500 per ton in FY23 from ₹8,300 in FY22 and ₹4,300 in FY21, primarily driven by a rise in Indonesian coal prices. Indonesian coal constitutes a majority of the imports (PFC, 2024).

Similarly, Rajasthan DISCOMs are paying a total of ₹7,439 crore towards changes in law dispensations (RERC, 2022). Both of these claims were settled after prolonged litigation for over five years and multiple regulatory and court orders. Almost a third of the expenses in Maharashtra and 60% of the claims in Rajasthan could be attributed to interest expenses or carrying cost due to delays in dispute resolution.

In conclusion, the significant cost escalation is due to substantial capacity addition, which leads to a step jump in cost trajectories. Some of these costs can be mitigated and optimised with a rigorous periodic planning exercise and competitive bidding for price discovery. Escalation in cost is also due to challenges with fuel availability and price volatility, which apply to both cost-plus and competitively bid projects. The cost impact is also exacerbated with delays in regulatory dispensations, which contribute to the interest burden/carrying cost.

4.2 Lack of timely cost recovery due to delays in settling matters before APTEL

Regulatory orders which have cost implications for the DISCOM are often challenged before APTEL. Improvements in the processes associated with SERC orders and their transparency and quality could reduce the number of appeals before APTEL. Even so, prompt and decisive orders from APTEL or higher courts would provide certainty and finality regarding the cost implications for DISCOMs. APTEL has been constituted with one chairperson and four members. However, in the past 15 years, the number of cases, complexity of issues, number of sector entities and even the number of DISCOMs and states have all increased. APTEL did attempt to set up regional circuit benches with offices in Chennai, Mumbai and Kolkata in 2012 to manage the cases before it, but these have been non-functional, perhaps because of the tribunal's limited membership (APTEL, 2012). Prolonged vacancies also make it challenging to resolve crucial matters in a time-bound manner (see Table 7). Of the 22 terms served by APTEL members across various posts, vacancies were not filled for more than a year in four instances and for 6 to 12 months in five instances.

Table 7: Number of months of vacancy between appointments since inception of APTEL

No. of months of vacancy between appointments					
	Chairperson	**Judicial Member**	**Technical Member**	**Technical Member**	**Technical Member P&NG**
1st to 2nd	6 months	1 month	6 months	6 months	4 months
2nd to 3rd	Less than 1 month	3 months	3 months	11 months	7 months
3rd to 4th	8 months	7 months	4 months	5 months	4 months
4th to 5th	Over 15 months	13 months	Over 13 months	10 months	Over 15 months
5th to 6th		7 months			
6th to 7th		Over 11 months			

Source: Compiled from APTEL annual reports and website, based on the analysis in (Chirayil, Dixit, & Josey, 2023)

The increased complexity of the sector and lack of sufficient members has also resulted in pending cases. Between FY19 and FY24, the ratio of pending cases to filed cases ranged from 23% to 91%, with higher pending cases at times of vacancies (see Table 8).

Table 8: Number of filed, disposed and pending cases before APTEL

As on Date	Filed	Disposed	Pending	Disposed/Filed	Pending/Filed
31 December 2006	485	237	248	49%	51%
31 December 2007	1,165	947	218	81%	19%
31 March 2009	1,801	1,347	454	75%	25%
31 December 2009	2,183	1,740	443	80%	20%
31 December 2010	2,724	2,066	658	76%	24%
30 November 2011	3,218	2,464	754	77%	23%
30 November 2012	4,169	3,640	529	87%	13%
31 December 2013	5,179	4,527	652	87%	13%
30 November 2014	6,102	5,304	798	87%	13%
30 November 2015	7,002	6,149	853	88%	12%
31 December 2016	8,431	6,160	1,271	73%	15%
31 December 2017	10,038	8,441	1,597	84%	16%
31 March 2019	12,175	9,872	2,303	81%	19%
31 December 2019	14,368	11,072	3,296	77%	23%
31 December 2020	16,725	12,388	4,337	74%	26%
31 December 2021	19,328	14,507	4,821	75%	25%
31 December 2022	6,221	4,056	2,165	65%	35%
31 March 2024	4,080	4355	3,709	107%	91%
31 December 2024	7,748	5121	2,627	66%	34%

Source: Compiled from annual reports of the Ministry of Power.

Many of the cases which have been pending for long periods before APTEL have a significant impact on consumer tariffs, and prolonged non-recovery of disputed amounts contributes to the build-up of interest cost. Some cases from across states have been detailed to highlight the magnitude of the challenge:

Maharashtra: MSEDCL challenged the regulatory order in Case No. 322 of 2019 dated 30 March 2020 through Appeal No. 65 of 2022. The appeal contested the methodology employed for agricultural demand estimation (MERC, 2025). Over an eight-year period, application of this disputed methodology resulted in cost disallowances exceeding ₹24,000 crore. However, the matter has remained pending before APTEL since September 2020, representing a delay of almost five years.

Uttar Pradesh: In 2019, the regulatory commission wrote off regulatory assets totalling ₹40,541 crore accumulated until FY18 against the UDAY grant in lieu of debt takeover. However, the Government of Uttar Pradesh adjusted the UDAY grant against pending subsidy claims and outstanding dues from public bodies rather than applying it to the regulatory asset. This created a situation where DISCOMs were neither permitted to recover these receivables from consumers nor compensated by the state government for the write-off. According to the DISCOMs' calculations, this treatment has resulted in regulatory assets to be recovered from consumers of ₹61,517 crore by FY24 instead of the anticipated regulatory surplus of ₹13,337 crore. This accounting discrepancy implies that rather than the 30% one-time tariff reduction initially determined by the Commission, consumers in Uttar Pradesh face a potential 60% one-time tariff increase. Since 2020, the DISCOMs have filed four appeals before APTEL on this issue, all of which remain pending. In the absence of regulatory clarity, DISCOMs are incurring significant working capital borrowing to manage revenue deficits arising from this unresolved matter (UPERC, 2024).

Telangana: The Telangana DISCOMs entered into an agreement with the Chhattisgarh DISCOMs for 1,000 MW from Marwa Thermal Power Station. The variable charges under this agreement are lower than those for all other contracted thermal power in Telangana, including power from pit-head plants (Sreekumar & Chirayil, 2020). Despite experiencing power shortages and resorting to costly market-based procurement, the Telangana DISCOMs have not been scheduling power from this relatively low-cost source due to ongoing disputes regarding tariffs and charges. This matter has remained pending before APTEL since 2018, creating a considerable financial impact of ₹4,400 crore on the Telangana DISCOMs through foregone cost savings and continued reliance on expensive alternative sources (APTEL, 2025d).

Madhya Pradesh: Under the State ERC regulations, power purchase quantum exceeding the normative distribution loss targets set by the Commission is subject to disallowance. However, the Commission would consider the power purchase rate based on actual costs incurred. In May 2021, during the true-up of costs for FY15 to FY18, the Commission determined that additional power purchases would necessitate the use of more expensive marginal generators, thereby increasing the average cost of procurement. Consequently, the Commission also adjusted the power purchase rate based on the power requirement as per the lower normative distribution loss, which reduced the average approved power purchase and resulted in higher disallowances of power purchase costs (MPERC, 2021). Aggrieved by this treatment, the DISCOMs filed an appeal seeking reconsideration of this methodology. Such reconsideration would require revisiting power procurement costs approved from FY15 onward and establishing a new methodology for future years. The matter remains pending before APTEL under Appeal No. 329 of 2022 since 2022. (MPCZ, 2025).

Tamil Nadu: In FY24, TANGEDCO, the state-owned DISCOM, reported 24 pending cases with an aggregate value of ₹7,085 crore across various legal forums, including APTEL (TNPDCL, 2024). The company has challenged several charges levied by TNERC, including renewable energy banking and wheeling loss determinations, before APTEL. The wheeling loss matter has been pending before APTEL since 2017 (APTEL, 2025c). Regarding banking charges, TANGEDCO challenged the regulatory commission's order before APTEL in 2018. TANGEDCO subsequently appealed this decision to the Supreme Court, where the matter remains sub-judice. During this extended litigation period, the existing renewable energy banking framework continues to operate, with TANGEDCO maintaining that the current charges do not reflect actual costs, particularly given the substantial increase in renewable energy banking volumes (TNERC, 2024).

Andhra Pradesh: In 1998, the State Electricity Board entered into a power purchase agreement with Hinduja National Power Corporation Limited (HNPCL), a private generating company. The project experienced significant delays and did not achieve financial closure until 2010. Following the commissioning of one unit in 2016, the ERC established an interim tariff for power procurement. However, this interim tariff became the subject of protracted litigation, with multiple disputes and appeals filed before APTEL and the Supreme Court between 2016 and 2020. In 2022, the Commission directed the execution of a fresh agreement between the parties and determined revised tariffs for the project (APERC, 2022). This order was subsequently challenged in 2023 and has remained pending before APTEL for over two years (APTEL, 2025b). The appeals encompass challenges to both capital cost determinations and energy charges approved since commissioning for this 1,040 MW project, which could have significant financial implications.

Similar regulatory uncertainties regarding cost disallowances and regulatory asset recognition have affected privately owned DISCOMs in Delhi, where tariff orders for 2013 and for the period from 2016 to 2022 have been challenged and remain pending before APTEL (Chitnis, DMonty Nair, & Singh, 2025).

Irrespective of the individual merits of specific cases, extended delays in judicial decision-making contribute to escalating interest costs and growing financial liabilities for the sector. These patterns underscore the critical importance of timely dispute resolution through measures such as augmenting APTEL's institutional capacity and establishing permanent regional benches to address the growing caseload more effectively.

4.3 Inadequate and infrequent tariff increases

A major factor contributing to DISCOMs' cash flow challenges is delayed revenue recovery stemming from irregular tariff determination processes and inadequate tariff increases. The High Level Panel on Financial Position of Distribution Utilities, chaired by Shri V.K. Shunglu, identified that many states failed to conduct tariff determinations each year (Planning Commission, 2011). Acting on the panel's recommendations and letters from the MoP, APTEL ruled in 2011 that tariff determination and true-up exercises must adhere to Commission-specified timelines, with Commissions issuing suo motu orders when there is delay in filing by more than one month (APTEL, 2011).Subsequent policy and compliance frameworks in FRP, UDAY and RDSS schemes have reinforced the importance of timely tariff revisions.

In recent years, tariff orders have been issued in a timely manner in most states. However, the approved increases frequently remain insufficient to cover DISCOMs' actual operational costs. Several SERCs have issued tariff orders but approved no tariff increases despite rising expenditures, widening the gap between cost recovery and approved revenues. Table 9 presents data on year-on-year tariff increases across seven states over a 21-year period, divided into 11 years before UDAY's implementation and 10 years after UDAY.

Table 9: Status of tariff revision for 21 years across seven states

State	Andhra Pradesh		Telangana	Madhya Pradesh		Maharashtra		Rajasthan		Tamil Nadu		Uttar Pradesh	
Period	**FY05-15**	**FY16-25**	**FY16-25**	**FY05-15**	**FY16-25**	**FY05-15**	**FY16-25**	**FY05-15**	**FY16-25**	**FY05-15**	**FY16-25**	**FY05-15**	**FY16-25**
Number of years with no year-on-year tariff increase	5	2	4	2	2	3	4	4	5	8	6	4	3
% of total years in period with no tariff increase	45%	20%	40%	18%	20%	27%	40%	36%	50%	73%	60%	36%	30%
Number of years with tariff increase > 10%	3	-	1	2	1	4	1	3	2	3	-	3	2
Year with > 10% increase as % of years with tariff increase	50%	0%	17%	22%	13%	50%	17%	43%	40%	100%	0%	43%	29%

Source: Analysis of tariff orders issued in these states from FY05 to FY25.

The analysis quantifies the proportion of years within each period when no tariff increases occurred, categorising whether this resulted from non-issuance of tariff orders or explicit decisions against tariff revision in issued orders. For years with approved increases, the data identifies instances where the annual average increases exceeded 10 percent.

Despite policy emphasis on regular tariff revisions, the number of tariff revisions post-UDAY have been limited. Although four states—Andhra Pradesh, Telangana, Tamil Nadu and Uttar Pradesh—showed modest improvements, significant gaps persist. Andhra Pradesh and Uttar Pradesh recorded no tariff revisions in 3 out of 10 years, while Telangana missed revisions in 4 years and Tamil Nadu in 6 years. Conversely, two states experienced declining revision frequency: Madhya Pradesh recorded no revisions in 2 out of 10 years, and Rajasthan had gaps in 5 out of 10 years. Maharashtra presents a unique case where the apparent fall in tariff revision frequency stems from a structural feature of the regulatory framework. The state's regulator determines tariffs for two-year periods within a single order, resulting in less frequent formal revisions. However, when combined with regular fuel surcharge adjustments, the overall tariff mechanism remains reasonably aligned with actual costs. Year-wise details of this compilation are shown in Table 10.

Table 10: Year-wise tariff changes across seven states for 21 years

Period	Year	Andhra Pradesh	Telangana	Madhya Pradesh	Maharashtra	Rajasthan	Tamil Nadu	Uttar Pradesh
Pre-UDAY	FY05	—	*State formed in June 2014. No tariff order was issued in FY15.*	**↑**	*No TO*	↑	*No TO*	—
	FY06	—		—	*No TO*	**↑**		*No TO*
	FY07	—		↑	↑	—		**↑**
	FY08	—		↑	**↑**	*No TO*		↑
	FY09	↑		↑	↑	—		↑
	FY10	**↑**		↑	**↑**	—		↑
	FY11	↑		**↑**	↑	↑	**↑**	—
	FY12	↑		↑	**↑**	↑	*No TO*	↑
	FY13	**↑**		↑	**↑**	**↑**	**↑**	**↑**
	FY14	**↑**		—	↑	**↑**	—	**↑**
	FY15	*No TO*	*No TO*	↑	↑	↑	**↑**	—
Post-UDAY	FY16	↑	↑	↑	—	**↑**	*No TO*	—
	FY17	—	↑	**↑**	↑	↑	*No TO*	↑
	FY18	↑	↑	↑	↑	↑	↑	↑
	FY19	↑	—	—	—	—	*No TO*	↑
	FY20	↑	—	↑	↑	—		**↑**
	FY21	↑	—	—	↑	**↑**		**↑**
	FY22	—	—	↑	—	—	↑	↑
	FY23	↑	**↑**	↑	—	—	—	↑
	FY24	↑	↑	↑	**↑**	—	↑	—
	FY25	↑	↑	↑	↑	↑	↑	—

Note: '—' is no change in tariff, '↑' is increase in tariff, '**↑**' is >10% increase in tariff, 'No TO': No Tariff Order (TO) by SERC.
Source: Analysis of tariff orders over the years for seven states with inputs from analysis in (PEG, 2020)

Besides this data, analysis of actual cost and revenue trends across 21 states from FY16 to FY23 reinforces the critical need for frequent and adequate tariff increases. In 11 states, the average annual billed revenue remained insufficient to cover annual costs. Five states—

Jharkhand, Telangana, Punjab, Uttar Pradesh and Tripura—demonstrated persistent misalignment between revenue billed and costs incurred across multiple years, contributing to accumulated losses. Three states—Assam, Maharashtra and Himachal Pradesh—experienced significant revenue gaps concentrated in specific years. Five states—Chhattisgarh, Gujarat, Haryana, Karnataka and Kerala—achieved revenue–cost alignment. Haryana experienced a notable reduction in revenue requirements due to enhanced state government support and decreased interest costs. Another group of five states—Bihar, Madhya Pradesh, Rajasthan, Tamil Nadu and Andhra Pradesh—implemented average tariff increases, but the increases were insufficient to address cost escalation, resulting in persistent revenue gaps. Madhya Pradesh showed some improvement as reduced cost escalation rates helped narrow revenue gaps. The details are provided in Annexure 6.

4.4 Delay in revenue recovery and subsidy payments

Beyond frequent tariff revisions, ensuring timely receipt of billed revenue and subsidy payments is critical for reducing the financial distress of DISCOMs. Among the seven states accounting for the majority of accumulated losses, revenue collection presents challenges in all states except Tamil Nadu. The Government of Tamil Nadu maintains a consistent track record of timely subsidy payments, and the state DISCOM, reports AT&C losses at manageable levels (PEG, 2020).

In FY24, DISCOMs reported state government subsidy requirement of ₹ 2.1 lakh crore. As the quantum is significant, delays in payment can have significant impact on DISCOM finances. Table 11 details the subsidy contributions to DISCOM revenue across 23 states between FY16 and FY24.

Table 11: Change in subsidy dependence between FY16 and FY24 in 23 states

States with Significant increase in subsidy dependance		
State	FY16	FY24
Madhya Pradesh	21%	44%
Karnataka	25%	41%
Punjab	24%	40%
Rajasthan	27%	36%
Chhattisgarh	4%	22%
Andhra Pradesh	13%	21%
Uttar Pradesh	13%	17%
Mizoram	0%	16%
Himachal Pradesh	6%	12%
Delhi	7%	11%
West Bengal	2%	5%
Tripura	0%	4%
Kerala	0%	2%

States where subsidy dependence has more or less remained the same		
State	FY16	FY24
Bihar	41%	41%
Tamil Nadu	13%	15%
Telangana	17%	15%
Gujarat	13%	13%
Maharashtra	12%	11%
Note: In these states subsidies have not changed by more than 2% of revenue between FY16 and FY24		
States with reduction in subsidy dependance		
State	FY16	FY24
Manipur	35%	26%
Jharkhand	32%	24%
Haryana	23%	15%
Assam	8%	2%
Meghalaya	3%	0%

Note: No revenue subsidy was reported in Odisha, Goa, Uttarakhand and Sikkim.
Source: Report on the performance of state power utilities (various years).

Five states—Madhya Pradesh, Karnataka, Punjab, Rajasthan and Bihar—demonstrate subsidy dependence ranging from 35% to 40% of total revenue. Except for Bihar, all these states have substantial agricultural consumption. In Punjab and Karnataka, subsidy growth reflects expanded coverage, including free power for domestic consumers with consumption of up to 200 units in Karnataka and extended subsidies to industrial consumers in Punjab.

In Telangana, Rajasthan, and Madhya Pradesh, agricultural consumers account for approximately 33-39% of the total DISCOMs' energy consumption[41] and are heavy subsidised. Four additional states—Chhattisgarh, Andhra Pradesh, Manipur and Jharkhand—exhibit subsidy dependence exceeding 20% of revenue. Thirteen of the 23 states show marked increases in subsidy dependence between FY16 and FY24. The increase in subsidy is quite stark in Madhya Pradesh, Karnataka, Punjab and Rajasthan. In five other states—Bihar, Maharashtra, Gujarat, Telangana and Tamil Nadu—the share of subsidy contribution to revenue has remained more or less the same but the quantum has increased substantially.[42] There is a reduction in the overall share of subsidies only in 5 out of 23 states. Even so, there has been an increase in the magnitude of subsidies even in these states.

Given this substantial dependence on subsidies, delays in payments significantly impact DISCOMs' cash flows and working capital requirements, resulting in higher interest costs. Table 12 presents an analysis of data on the subsidy billed and received from the 12 states which account for 90% of revenue subsidies billed in India. The table highlights the extent of year-on-year shortfalls in states.

Table 12: Shortfall (-)/ Surplus (+) in subsidy paid versus subsidy billed for the year

<table>
<tr><th>Year</th><th>Andhra Pradesh</th><th>Maharashtra</th><th>Rajasthan</th><th>Karnataka</th><th>Madhya Pradesh</th><th>Punjab</th><th>Uttar Pradesh</th><th>Tamil Nadu</th><th>Bihar</th><th>Gujarat</th><th>Telangana</th><th>Haryana</th></tr>
<tr><td>FY16</td><td>-1%</td><td>14%</td><td>-18%</td><td>3%</td><td>2%</td><td>-16%</td><td rowspan="9">0%</td><td rowspan="9">0%</td><td>0%</td><td>-1%</td><td>-7%</td><td rowspan="9">0%</td></tr>
<tr><td>FY17</td><td>-13%</td><td>-20%</td><td>-16%</td><td>-9%</td><td>5%</td><td>-9%</td><td>0%</td><td rowspan="7">0%</td><td>0%</td></tr>
<tr><td>FY18</td><td>-14%</td><td>15%</td><td>-15%</td><td>-14%</td><td>1%</td><td>-21%</td><td>34%</td><td>-19%</td></tr>
<tr><td>FY19</td><td>-79%</td><td>13%</td><td>-29%</td><td>-24%</td><td>-19%</td><td>5%</td><td>32%</td><td>-18%</td></tr>
<tr><td>FY20</td><td>15%</td><td>25%</td><td>-43%</td><td>-6%</td><td>-20%</td><td>2%</td><td>0%</td><td>-16%</td></tr>
<tr><td>FY21</td><td>-63%</td><td>-14%</td><td>-23%</td><td>-8%</td><td>-29%</td><td>-13%</td><td>-7%</td><td rowspan="4">0%</td></tr>
<tr><td>FY22</td><td>-2%</td><td>27%</td><td>17%</td><td>53%</td><td>5%</td><td>5%</td><td>-6%</td></tr>
<tr><td>FY23</td><td>23%</td><td>32%</td><td>2%</td><td>0%</td><td>20%</td><td>22%</td><td>-2%</td></tr>
<tr><td>FY24</td><td>0%</td><td>-9%</td><td>-14%</td><td>-16%</td><td>14%</td><td>4%</td><td>-4%</td><td>-2%</td></tr>
</table>

Source: Report on the performance of state power utilities (FY16 to FY24).

The state governments of Tamil Nadu, Haryana and Gujarat have consistently ensured timely subsidy payments. In Uttar Pradesh, the state government reports timely subsidy payment, but the state's DISCOMs were affected because the 'additional subsidy' identified by the regulator was not recognised or provided by the state government until recently (UPPCL, 2025). Delay in subsidy payments is a serious challenge in Rajasthan, Karnataka, Telangana and—in recent years—Bihar.

The implementation of RDSS after 2021 resulted in payment of outstanding subsidies, creating significant surpluses and eliminating shortfalls in Telangana, Andhra Pradesh, Madhya Pradesh and Punjab. However, FY24 witnessed renewed shortfalls in Maharashtra, Rajasthan and Karnataka. This development is particularly concerning because it suggests that even under RDSS's stringent conditions, sustaining consistent subsidy payment discipline remains challenging.

[41] Please see Annexure 15.

[42] In Uttar Pradesh's case, the share of subsidies has increased marginally between FY16 and FY24 but this amount does not include the additional subsidy which has provided later by the state government. This is also discussed in Section 4.1.2.

Between FY16 and FY24, the carrying cost alone for subsidy shortfall amounted to approximately ₹26,500 crore nationally.[43]

The six states shown in Table 13 accounted for the bulk of the shortfall and the consequent interest cost impact.

Table 13: Additional interest payments due to subsidy shortfall between FY16 and FY25

State	Additional interest payments due to subsidy shortfall between FY16 and FY25
	₹ Cr.
Rajasthan	9,408
Andhra Pradesh	5,335
Madhya Pradesh	3,592
Karnataka	2,587
Punjab	2,576
Telangana	2,072
Total for six states	**25,570**
National Total	**26,500**

Source: Authors analysis based on data from PFC reports for multiple years

4.4.1 Timely revenue recovery from all consumers

Delayed revenue recovery from consumers significantly impacts DISCOMs' finances. The all-India average receivables days stood at 124 in FY24, far exceeding an ideal 45-day cycle that aligns with power procurement payment schedules. Delays of over 10 months were reported in Uttar Pradesh, Manipur and Jharkhand. In Uttar Pradesh, domestic consumers—comprising nearly half the state's total sales—constitute the bulk of outstanding receivables. Five states—Bihar, Maharashtra, Tripura, Telangana and Meghalaya—recorded delays between 7 and 10 months. Notably, in Maharashtra, agricultural sales represent only 26% of total sales but account for 70% of outstanding receivables.

An analysis of three-year average receivables (FY17–20 vs. FY21–24, detailed in Annexure 7) reveals mixed trends: seven high-receivables states showed improvement, while eight states showed deterioration. However, nine states maintained relatively healthy receivables below 70 days. Importantly, Rajasthan and Tamil Nadu demonstrate that even states with substantial financial losses can still consistently achieve timely revenue recovery from consumers.

4.4.2 Dues from government departments and public bodies

Government departments and public bodies accounted for the majority of receivables in Andhra Pradesh, Telangana, and Tamil Nadu in FY22. By FY24, the quantum of government dues had reduced significantly in Maharashtra and Telangana, and marginally in Rajasthan. However, despite RDSS conditionalities requiring clearance of pending government dues, the outstanding amounts increased starkly in Uttar Pradesh and Andhra Pradesh, and rose marginally in Tamil Nadu and Madhya Pradesh by FY24 (see Table 14).

[43] Data on the annual shortfall is calculated as the difference between the subsidy billed and subsidy received each year as reported by PFC in the report on the performance of state power utilities. Interest costs were estimated by assuming a nominal carrying cost of 10% per annum for each year of the shortfall.

Table 14: Outstanding dues from government departments and public bodies

Share of government dues in total receivables from consumers						
DISCOMs in state	**FY22**			**FY24**		
	Government dues	**Receivables from sale of power**	**Government dues as % of receivables**	**Government dues**	**Receivables from sale of power**	**Government dues as % of receivables**
Unit	₹ Cr.	₹ Cr.	%	₹ Cr.	₹ Cr.	%
Andhra Pradesh	9,663	12,380	78%	15,157	20,283	75%
Madhya Pradesh	941	11,055	9%	1,122	13,766	8%
Maharashtra	9,163	46,622	20%	6,182	59,808	10%
Rajasthan	1,575	4,977	32%	1,283	3,677	**35%**
Tamil Nadu	3,810	7,678	50%	5,987	10,144	**59%**
Telangana	13,039	17,640	74%	4,751	30,461	16%[44]
Uttar Pradesh	5,224	84,175	6%	13,910	66,308	**21%**

Source: (MoP, 2022),state-wise annual audited financial statements/reports for FY24.

4.4.3 Age of receivables

Outstanding receivables' age presents another critical challenge. Five states accounted for 75% of national receivables in FY23 (Table 15), with 37% of these dues pending for over three years on average. Recovery of such aged receivables remains unlikely despite improvements in metering and billing. These receivables are being provisioned and will likely improve the overall collection efficiency in the future. Writing off these receivables will affect DISCOM finances or require state government support.

Table 15: Age-wise receivables in FY23

Receivables (₹ Cr.)	FY2022–23	0 to 6 months	6 months to 1 year	1 to 2 years	2 to 3 years	>3 years
Uttar Pradesh	75,581	0%	17%	19%	24%	40%
Telangana	24,299	17%	22%	8%	2%	51%
Maharashtra	50,255	42%	7%	12%	9%	29%
Karnataka	13,726	43%	8%	14%	10%	25%
Andhra Pradesh	15,118	20%	13%	9%	17%	41%
Total for 5 states	**1,78,979**	**19%**	**14%**	**14%**	**15%**	**37%**

Source: State-wise annual audited financial statements/reports for FY23.

4.5 Build-up of working capital loans implies borrowing is not translating to investments

DISCOMs have to manage operational expenses despite increase in costs, lack of cost-reflective tariffs and poor revenue recovery. This has led to significant borrowing to meet working capital requirements in the past. In fact, more than 90% of the debt taken over under

[44] While annual reports show relatively low contribution of government department and public body dues in Telangana in FY24, regulatory filings of DISCOMs show a higher number. As per DISCOM reports, arrears of public water schemes (including lift irrigation schemes) and streetlight schemes consumers over Rs.50,000 pending for over six months was as high as ₹20,240 crore which is equivalent to 66% of the outstanding receivables for FY24.

UDAY was incurred to meet the working capital requirements of DISCOMs. As mentioned earlier, there were specific conditionalities under UDAY to restrict borrowing to 25% of DISCOM revenue and to avoid short-term borrowing from scheduled commercial banks. However, systematic reporting of DISCOM borrowing by end use remains inadequate, and the status of borrowing across DISCOMs is challenging to analyse (PEG, 2025; ETPI, 2023).[45] This chapter seeks to build further evidence to highlight DISCOM stress and the extent of built-up post-UDAY working capital liabilities.

4.5.1 Borrowing by DISCOMs is for working capital rather than for capital investments

To understand the quality of debt and its implications for DISCOMs' capital investments, data from FY21 to FY24 from 22 states was analysed. In the analysis, growth in assets in this period was juxtaposed with growth in funds available with the DISCOMs through borrowing, consumer contributions and grants. Using the data from PFC's reports on the performance of state power utilities, data was compiled on net tangible assets, depreciation and outstanding capital works in progress. This was used to estimate the growth in assets in this period. Similarly, PFC data on outstanding borrowing, government grants and consumer contributions for capital works was compiled.

To estimate the growth in assets between FY21 and FY24, the growth in net tangible assets in the period was added to the accumulated depreciation in this period along with the outstanding capital works in progress (CWIP) as on 31st March 2024.

For growth in funds available in the same period, the change in outstanding borrowing between FY21 and FY24 was captured. This was added to the aggregated total of outstanding government grants and consumer contributions[46] reported for the first three years of the four-year period.[47]

The growth in assets captured here is compared to the growth in funds, as shown in Table 16. From the analysis, it is clear that in 14 of the 22 states analysed, 50% of the growth in funds available did not contribute to asset growth in this period.[48] **This implies that borrowing and funds provided to the DISCOM does not translate into asset creation, a clear indication of DISCOM financial stress.**

This analysis is a first-order estimation to provide a sense of the magnitude of the challenge. t is likely that the role of grants and consumer contribution is overestimated but if the quantum of such funds is reduced, it implies that asset growth receives even less funds from DISCOMs, exacerbating the challenge.

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45 Unlike subsidies or generator payables, borrowing data lacks systematic public disclosure by PFC or the MoP. The Electricity Distribution (Accounts and Additional Disclosure) Rules, 2024 have improved reporting in annual financial audits in many states, with additional information available through regulatory processes in some states.

46 It must be noted that PFC captures the outstanding government grants and consumer contributions reported by DISCOMs in their annual accounts. DISCOMs amortise part of the grants and consumer contribution outstanding each year to the P/L account, and the amounts reported are net of this amortisation and thus is an underestimate.

47 For this analysis, it is assumed that grants/consumer contributions provided must be utilised within a 1–2 year period towards capital works. Thus, the entire outstanding grants and consumer contributions reported for the first three years of the period are assumed to be utilized in the four-year period.

48 The data in the case of Tamil Nadu may not be representative because the accounts reported by PFC also included data from the generation business of the then bundled utility, and the nature of capital investments for coal generation capacity is quite different from that in the distribution business.

Table 16: Growth in assets versus fund availability for DISCOMs in 22 states (FY21 to FY24)

Growth in assets versus fund availability for DISCOMs in 22 states (FY21 to FY24)											
State	**Δ in net tangible assets (FY21–24)**	**Total depreciation in period (FY21–24)**	**Outstanding CWIP (FY24)**	**Δ in Assets**	**Total consumer contribution in the period (FY21–23)**	**Total government grants in the period (FY21–23)**	**Δ in total borrowings (FY21–24)**	**Δ in net funds**	***Difference btw Δ in assets and Δ in net funds***	**Growth in assets as a % of growth in funds**	**% share of funds growth not attributable to growth in assets**
Unit	₹ Cr.	₹ Cr.	₹ Cr.	₹ Cr.	₹ Cr.	₹ Cr.	₹ Cr.	₹ Cr.	₹ Cr.	%	%
Andhra Pradesh	6,359	6,736	7,880	20,975	17,361	26,831	34,335	78,527	57,552	27%	73%
Assam	753	1,651	7,676	10,080	879	22,717	-906	22,690	12,610	44%	56%
Bihar	6,888	6,329	5,067	18,284	0	43,853	2,622	46,475	28,191	39%	61%
Chhattisgarh	2,378	2,114	2,503	6,995	5,793	12,168	1,259	19,220	12,225	36%	64%
Gujarat	4,458	8,122	1,577	14,157	16,935	10,556	-355	27,136	12,979	52%	48%
Haryana	2,530	3,752	1,586	7,868	5,736	4,758	10,230	20,724	12,856	38%	62%
Himachal Pradesh	993	1,833	1,200	4,026	2,920	2,328	522	5,770	1,744	70%	30%
Jharkhand	4,150	3,796	627	8,573	0	25,207	2,936	28,143	19,570	30%	70%
Karnataka	9,971	8,688	1,642	20,301	24,876	7,294	9,690	41,860	21,559	48%	52%
Kerala	-746	6,652	3,879	9,785	0	11,266	-1,581	9,685	-100	101%	-1%
Madhya Pradesh	1,360	6,159	10,338	17,857	13,123	12,306	142	2,5571	7,714	70%	30%
Maharashtra	1,138	15,209	3,253	19,600	7,440	24,988	45,917	78,345	58,745	25%	75%
Manipur	1,484	263	378	2,125	0	6,325	256	6,581	4,456	32%	68%
Meghalaya	281	228	1,298	1,807	117	3,238	315	3,670	1,863	49%	51%
Punjab	1,534	5,225	4,126	10,885	11,215	2,602	4,574	18,391	7,506	59%	41%
Rajasthan	9,667	12,066	3,137	24,870	28,503	26,308	39,196	94,007	69,137	26%	74%
Tamil Nadu	-8,225	14,993	64,189	70,957	0	11,141	35,889	47,030	-23,927	151%	-51%
Telangana	2,365	5,205	2,135	9,705	14,799	3,741	15,095	33,635	23,930	29%	71%
Tripura	146	111	1,373	1,630	0	4,205	299	4,504	2,874	36%	64%
Uttar Pradesh	9,467	12,440	8,984	30,891	29,494	20,351	-14,015	35,830	4,939	86%	14%
Uttarakhand	1,741	1,574	1,457	4,772	2,758	5,587	179	8,524	3,752	56%	44%
West Bengal	4,793	5,706	2,814	13,313	14,993	44,930	179	60,102	46,789	22%	78%

Source: Authors' analysis based on data from PFC reports on Performance Report on Power Utilities

This analysis is only for the period between FY21 and FY24, but the broad findings of high working capital borrowing are also corroborated by reporting on the extent of working capital loans available in some states.

4.5.2 Extent of working capital borrowing across states

Explicit reporting of working capital borrowing was observed in eight states for FY23 and FY24 (see Table 17). These states accounted for 51% of sales and 43% of accumulated losses at the national level in FY24.

Table 17: Extent of working capital borrowing in FY24 and FY23

State	Working capital borrowing (₹ Cr.)		% Year-on-year growth	Working capital borrowing as (%) of total borrowing	
	FY23	FY24		FY23	FY24
Andhra Pradesh	32,342	46,066	42%	62%	69%
Bihar	9,729	8,933	-8%	70%	68%
Haryana	5,126	7,468	46%	43%	44%
Karnataka	7,743	11,316	46%	46%	57%
Maharashtra	46,784	73,827	58%	79%	86%
Punjab	8,825	10,745	22%	50%	53%
Rajasthan	56,380	65,442	16%	71%	71%
Telangana	21,565	37,494	74%	60%	81%

Note: The data for Karnataka was available for only two DISCOMs, namely, BESCOM and MESCOM.
Source: Annual audited financial statements/reports for DISCOMs in Andhra Pradesh, Bihar, Haryana, Maharashtra and Telangana. Regulatory filings for Karnataka, Punjab and Rajasthan.

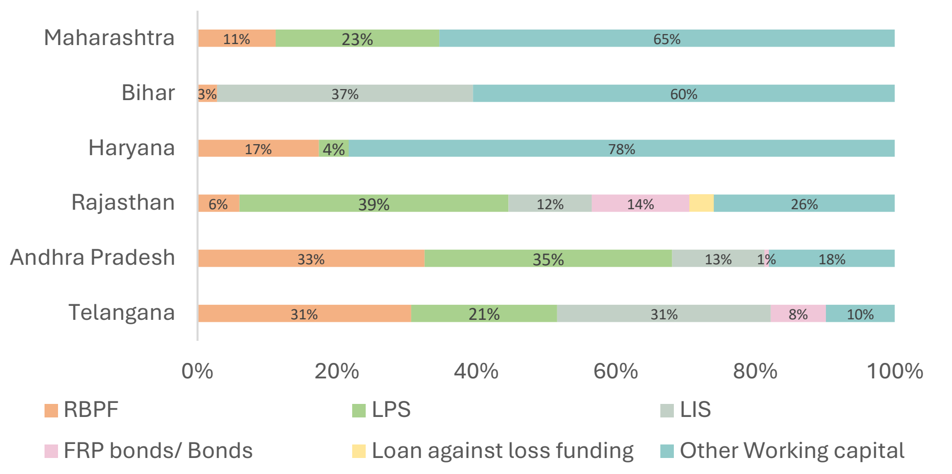
Working capital loans dominated DISCOM borrowing across states in FY24. Seven of eight states reported over 50% of total loans as working capital, with Maharashtra (86%) and Telangana (81%) leading. Rajasthan, Bihar and Andhra Pradesh each recorded approximately 70%.

There was also a sharp year-on-year increase in non-capex loans between FY23 and FY24, indicating that working capital accumulation is a current crisis, not merely a legacy issue. For the one year period, Telangana recorded 74% growth in working capital borrowing and Maharashtra 58%, while Andhra Pradesh, Karnataka, and Haryana each recorded a growth of 42–46%. Rajasthan and Punjab showed moderate growth of 16-22%. Only Bihar reduced working capital borrowing during this period.

4.5.3 End-use break-up of working capital loans

These loans encompass all non-capex borrowing: working capital loans, LPS and LIS loans, Revolving Bill Payment Facility (RBPF), cash credits/overdrafts and DISCOM borrowing under UDAY and FRP schemes. State-wise loan breakdowns are detailed in Figure 2.

Figure 2: End-use of working capital loans as reported by DISCOMs



Note: The data for Karnataka was available for only two DISCOMs, namely, BESCOM and MESCOM.
Source: Annual audited financial statements/reports for DISCOMs in Andhra Pradesh, Bihar, Haryana, Maharashtra and Telangana. Regulatory filings for Karnataka, Punjab and Rajasthan.

While the LPS and LIS schemes drove increased borrowing in Maharashtra, Bihar and Haryana, the DISCOMs in the three other states primarily borrowed for other operational and working capital needs.

Working capital build-up persists despite UDAY debt takeover, reflecting operational challenges beyond LPS/LIS implementation. Analysis of working capital borrowing from FY16 to FY24 in Maharashtra, Karnataka and Rajasthan reveals that working capital comprised 40–50% of the total borrowing in Maharashtra and Karnataka, and 85–90% in Rajasthan before UDAY debt takeover (Table 18). Although debt takeover temporarily reduced these shares by 2020, there was also a steady accumulation of borrowing which restored pre-UDAY levels in Karnataka and Rajasthan. Maharashtra's build-up now exceeds pre-UDAY levels, indicating persistent operational inefficiencies.

Table 18:Build-up of working capital loans in three states

Karnataka	Working capital borrowing (₹ Cr.)	WCB as (%) of total borrowing	Rajasthan	Working capital borrowing (₹ Cr.)	WCB as (%) of total borrowing	Maharashtra	Working capital borrowing (₹ Cr.)	WCB as (%) of total borrowing
FY16	3,969	51%	FY16	67,461	84%	FY16	7,806	41%
FY17	4,154	47%	FY17	65,306	89%	FY17	9,646	43%
FY18	4,079	45%	FY18	53,917	85%	FY18	11,320	56%
FY19	4,308	43%	FY19	40,281	74%	FY19	6,669	24%
FY20	5,113	42%	FY20	31,973	65%	FY20	21,441	64%
FY21	5,593	38%	FY21	39,534	75%	FY21	27,800	64%
FY22	7,317	48%	FY22	46,024	70%	FY22	31,663	69%
FY23	7,743	46%	FY23	56,380	71%	FY23	46,784	79%
FY24	11,316	57%	FY24	65,442	71%	FY24	73,827	86%

Source: Annual audited financial statements/reports for Maharashtra. Regulatory filings for Karnataka and Rajasthan.

4.5.4 Dues to state-owned generation and transmission companies

DISCOM indebtedness is not limited to increased working capital borrowing alone but also extends to significant dues owed to state-owned generating and transmission companies. The enforcement of LPS Rules remains limited in effectiveness when applied to state-owned electricity utilities, which are sister concerns of the DISCOMs.

As observed in Table 19, payables (in days) to state-owned generating companies are higher than overall payables for power purchase in Rajasthan, Uttar Pradesh, Karnataka, Maharashtra, Andhra Pradesh, West Bengal and Assam. With the exception of West Bengal, all states showed a reduction in payables to state generating companies since the launch of LPS Rules. However, the payables continued to be significant, ranging from approximately 6–7 months in Uttar Pradesh, Rajasthan, Andhra Pradesh and West Bengal; almost 1 year in Maharashtra; and almost 2 years in Karnataka.

Table 19:Payables (days) by DISCOMs to state generation and transmission companies

Payables (days) for all power purchase compared with payables to state generation companies (state Gencos) and state transmission companies (state Trancos) in FY22 and FY23						
States	**FY22**			**FY23**		
	Overall Payables (days) for Power Purchase	**Payables (days) for State Gencos**	**Payables (days) for State Transcos**	**Overall Payables (days) for Power Purchase**	**Payables (days) for State Gencos**	**Payables (days) for State Transcos**
Jharkhand	536	145	1237	433	223	1452
Telangana	380	293	234	296	233	226
Meghalaya	284	214	38	273	114	112
Tamil Nadu	223	Not available	103	171	Not available	56
Madhya Pradesh	217	173	387	207	194	376
Rajasthan	203	536	455	88	198	323
Uttar Pradesh	203	229	721	172	197	683
Karnataka	186	817	133	174	675	142
Chhattisgarh	181	248	261	116	102	38
Maharashtra	177	448	240	113	326	281
Andhra Pradesh	166	307	291	85	212	222
Bihar	148	Not available	947	104	Not available	1027
West Bengal	147	177	125	143	220	98
Himachal Pradesh	67	Not available	295	34	Not available	0
Haryana	45	58	36	62	37	51
Punjab	45	Not available	97	55	Not available	119
Assam	37	114	142	59	105	120
Uttarakhand	24	69	54	45	67	87
Odisha	56	35	53	47	78	39

Source: Report on the performance of state power utilities (various years).

DISCOM payables to state transmission companies are even more substantial: more than 9 months in Maharashtra and Rajasthan; 1 year in Uttar Pradesh and Madhya Pradesh; and more than 2 years in Bihar and Jharkhand.

Despite multiple restructuring schemes with several conditionalities aimed at rationalising power procurement costs, improving revenue recovery, and ensuring timely revision of tariffs and subsidy payments, there has been a continued build-up of losses. Additionally, longer-tenure loans to clear generator dues have helped address the build-up of payables, but this approach requires complementary measures, including a clear plan for future revenue recovery, particularly given the associated interest cost build-up. Further, measures towards least-cost power procurement planning, cost-reflective tariffs and revenue recovery require sustained implementation efforts over time.

Key takeaways

— Persistent debt quality issues characterise DISCOMs' borrowings. Data from eight states shows that as of 31 March 2024, approximately 44% to 86% of the total borrowings were for working capital purposes rather than for capital investments. Between FY23 and FY24, these borrowings grew at a rate of 16% to 74% in seven of the eight states. LPS and LIS schemes are not the sole contributors to working capital borrowing build-up. These liabilities constrain DISCOMs' ability to invest in network improvements and service quality.

— Seven states—Tamil Nadu, Uttar Pradesh, Rajasthan, Madhya Pradesh, Maharashtra, Telangana and Andhra Pradesh—account for 78% of the total losses. The reasons for loss build-up in these and other states include the following:

- **Issues with power procurement planning and pricing**: Lack of periodic assessment of demand-supply requirements, absence of least-cost planning approaches, and challenges with fuel availability and price volatility
- **Delays in regulatory dispensations**: Disputes between parties and appeals on regulatory commission orders remain pending for years, creating uncertainty and carrying cost build-up. Pendency before APTEL extends for years, exacerbated by unfilled vacancies in APTEL, which contribute to this uncertainty.
- **Inadequate and infrequent tariff increases**: Despite policy initiatives to ensure timely annual tariff orders over the past decade, a marginal improvement in tariff revision has been observed after UDAY. When tariff orders are issued, no tariff increase is approved in 40% to 60% of instances in Telangana, Tamil Nadu and Rajasthan and in 20% to 30% of instances in Uttar Pradesh and Madhya Pradesh. In the years where tariff increase was approved, a substantial increase of more than 10% was observed in 40% of instances in Rajasthan, 29% in Uttar Pradesh and 13–17% in Telangana and Madhya Pradesh.
- **Delay in revenue recovery, subsidy payments**: The increased dependence on subsidies in total revenue makes timely subsidy payments crucial. In fact, five states—Madhya Pradesh, Karnataka, Punjab, Rajasthan and Bihar—demonstrate subsidy dependence ranging from 35 to 40% of total revenue. Delays in subsidy payments have substantial implications for interest cost. Between FY16 and FY24, delay in subsidy payments resulted in an interest cost build-up of ₹26,500 crore nationally. Although the RDSS launch has led to significant improvements in subsidy payments and government dues, the sustainability of this improvement remains to be assessed. Pending consumer dues represent a major challenge in six of the seven identified states. Approximately 40% of receivables are more than three years old, suggesting limited recovery prospects and necessitating provisioning.

Recommendations:

- Addressing past losses and liabilities remains critical for improving DISCOMs' financial health and preventing the build-up of future losses. This continues to be central to any financial turnaround strategy for DISCOMs.
- Beyond liability takeovers, it is equally important to address the underlying drivers of loss accumulation. These include inefficiencies in power procurement planning and pricing, infrequent tariff revisions, delays in recovering revenue (including subsidies and government department dues) and payment delays arising from disputes and litigation. Except for the last point, these factors were already identified as conditionalities in past financial restructuring schemes. However, without clear monitoring, sustained incentives and enabling state-level policy and regulatory frameworks, they may continue to remain unresolved.
- Faster dispute resolution on tariff-related matters with cost implications can be facilitated by expanding APTEL's capacity through additional members and operationalising regional benches. This requires broader reforms supported by the central government.
- DISCOMs' financial stress is underscored by their heavy reliance on working capital borrowings, rising receivables from consumers and large payables to state-sector utilities. However, there is no systematic, centralised reporting on these indicators. As more states improve disclosures through annual audited financial statements/reports, it is crucial to establish centralised, public tracking of the following: working capital loans (with end use and tenors), consumer-category-wise ageing of receivables and payables to state generating and transmission companies.

5 Implications of measures for addressing the financial challenges of DISCOMs

From the analysis in the previous chapter, it is clear that achieving financially sustainable DISCOMs in the medium term requires a comprehensive approach involving the following elements:

- Systematic resolution of outstanding losses
- Improvements in power procurement planning to meet reliability requirements through a least cost approach
- Strengthening revenue collection frameworks
- Implementation of cost-reflective tariff structures

This chapter examines the quantitative impact and policy implications of these strategic interventions on the financial health and operational efficiency of DISCOMs.

5.1 Addressing outstanding losses

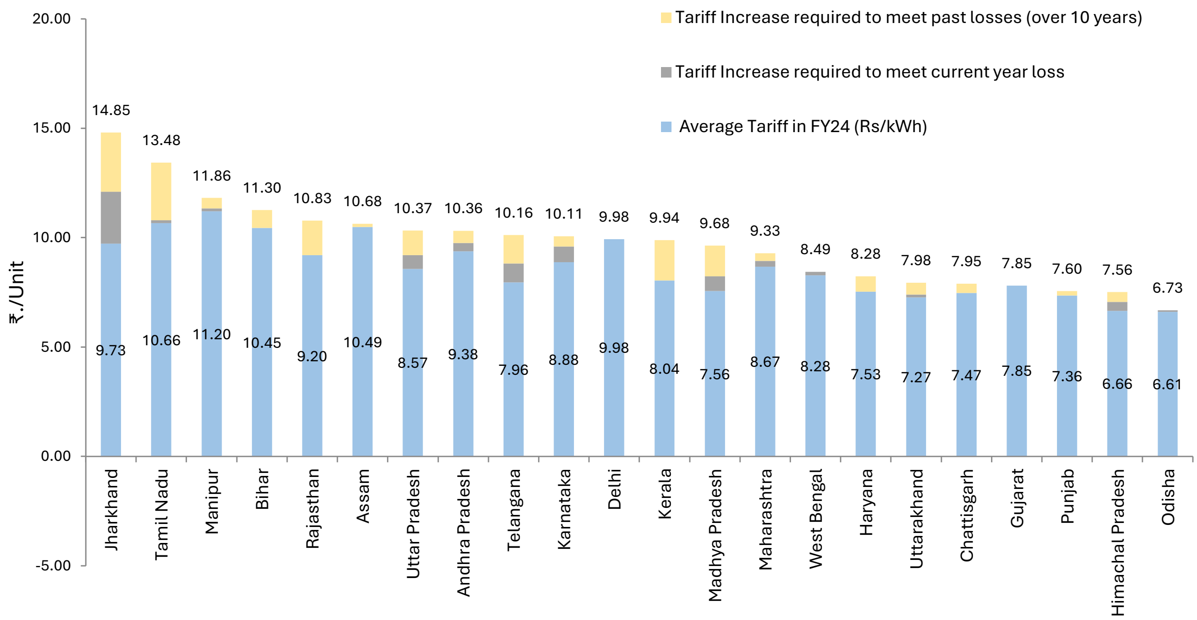
To address the accumulated losses of ₹7.08 lakh crore, two distinct approaches are possible. The first approach involves recovering these losses through prospective tariff adjustments. The second approach involves takeover by state governments, as in the case of UDAY.

5.1.1 Impact of tariff increase to cover outstanding losses over a 10-year period

The option of tariff increase presents significant challenges in states where loss accumulation primarily stems from regulatory disallowances of costs deemed imprudent, making tariff-based recovery legally unfeasible. Even assuming that all accumulated losses qualify for legitimate recovery through consumer tariffs, the requisite tariff increases over a 10-year amortization period would impose a substantial burden on consumers, as demonstrated for 22 states in Figure 3. A longer amortisation duration for tariff-based recovery of losses would be challenging to estimate and implement, given the many structural changes in the consumer sales mix faced by DISCOMs.

Figure 3 illustrates the per-unit tariff increase required from FY25 onwards to recover the accumulated losses up to FY24 over a 10-year period and the annual losses incurred. The tariff increase required on both accounts is presented as an incremental adder to the average consumer tariff prevailing in FY24. Notably, these calculations exclude the additional 3–4% annual tariff escalation typically required to accommodate routine cost increases.

Figure 3: Tariff increase required if past losses are met through consumer tariff increase



Source: Authors' analysis based on data from (PFC, 2025).

In 10 of the 22 states analysed, the required tariff increase would result in average tariffs ranging from about ₹10 to ₹14 per unit. This translates to substantial percentage increases: More than 50% in Jharkhand, 28% in Madhya Pradesh and Telangana, 26% in Tamil Nadu, 24% in Kerala, 21% in Uttar Pradesh and 18% in Rajasthan. Additionally, an increase of between 10% to 15% would be required in five states, namely, Karnataka, Himachal Pradesh (14%), Andhra Pradesh (11%), Haryana and Uttarakhand (11%).

Should regulators implement tariff increases of this magnitude, two critical outcomes are anticipated. First, subsidy payouts for subsidised consumer categories (agriculture, domestic, etc.) would increase significantly to maintain affordability for these segments. Second, tariffs for C&I enterprises would become even more uncompetitive relative to open access and captive generation options, potentially accelerating consumer migration away from DISCOM supply and further eroding DISCOMs' revenue base. With tariffs exceeding ₹10/unit, consumers can procure solar along with storage, which is available less than ₹6/unit (see Section 7.3 for more details). Therefore, such tariff increases would be uncompetitive given the alternative supply options available, resulting in revenue and sales attrition of DISCOMs.

5.1.2 Addressing past liabilities or losses by issuing state government bonds

Past liabilities can alternatively be addressed through bonds issued by state governments. Due to the absence of specific data on eligible liabilities, the fiscal impact is estimated based on the state assuming all the financial losses (both annual and accumulated as of 31 March 2024). The takeover would be implemented through 20-year bonds. These bonds are assumed to follow the UDAY bond structure[49].

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[49] The coupon rates could be set at the State Government Securities rates plus a 0.75% spread (0.5% base spread + 0.25% for non-SLR status) or the prevailing market-determined rates, whichever is lower.

A one-time takeover of ₹7.45 lakh crore of losses (accumulated and annual) across 22 states through issue of 20-year bonds would result in an annual state government budget outlay of ₹77,000 crore, as detailed in Table 20.

Table 20: Impact of one-time loss takeover by state government on fiscal deficit

Impact of loss takeover on fiscal deficit							
State	**Fiscal Deficit (FD)/GSDP (FY24)**	**Accumulated deficit of DISCOMs (FY24)**	**Annual gap (FY24)**	**Total losses (FY24)**	**Coupon rate[50]**	**Annual outgo due to takeover from FY25**	**Annual outgo as % of GSDP (FY25)**
Unit	%	₹ Cr.	₹ Cr.	₹ Cr.	%	₹ Cr.	%
Meghalaya	5.90%	4,634	196	4,830	8.00%	492	0.84%
Tamil Nadu	**3.40%**	**1,66,944**	**1,206**	**1,68,150**	**8.22%**	**17,411**	**0.59%**
Rajasthan	**4.30%**	**91,565**	**-503**	**91,062**	**8.40%**	**9,552**	**0.55%**
Madhya Pradesh	**3.30%**	**69,301**	**4,861**	**74,162**	**8.23%**	**7,682**	**0.52%**
Telangana	**3.40%**	**67,276**	**6,397**	**73,673**	**7.95%**	**7,477**	**0.46%**
Jharkhand	1.40%	18,469	2,369	20,838	8.10%	2,138	0.40%
Uttar Pradesh	**3.10%**	**89,662**	**7,036**	**96,698**	**8.23%**	**10,018**	**0.38%**
Kerala	**3.00%**	**35,978**	**-226**	**35,752**	**8.18%**	**3,689**	**0.29%**
Haryana	**2.90%**	**28,001**	**-275**	**27,726**	**8.22%**	**2,869**	**0.24%**
Andhra Pradesh	**4.40%**	**29,210**	**2,725**	**31,935**	**8.25%**	**3,313**	**0.21%**
Bihar	4.10%	18,503	-1,193	17,310	7.91%	1,751	0.18%
Chhattisgarh	5.30%	10,016	-32	9,984	8.00%	1,017	0.18%
Himachal Pradesh	5.30%	3,754	465	4,219	8.00%	430	0.18%
Tripura	0.80%	1,171	155	1,326	8.00%	135	0.17%
Uttarakhand	2.30%	5,435	180	5,615	8.00%	572	0.17%
Karnataka	**2.60%**	**26,109**	**5,538**	**31,647**	**8.40%**	**3,320**	**0.12%**
Punjab	4.30%	9,620	-776	8,844	8.22%	916	0.10%
Maharashtra	**2.20%**	**36,226**	**3,751**	**39,977**	**8.01%**	**4,075**	**0.09%**
Manipur	4.30%	295	11	306	8.00%	31	0.06%
Assam	3.70%	1,324	-265	1,059	7.87%	107	0.02%
Gujarat	1.00%	-5,165	-7,249	-	8.00%	0	0.00%
Odisha	1.80%	-824	345	-	7.95%	0	0.00%
West Bengal	3.30%	-158	873	715	8.18%	74	0.00%
Total	3.00%	7,13,493	36,107	7,45,828		77,067	0.24%

Source: Authors' analysis based on data from (PFC, 2025; RBI, 2024)

Ten states (highlighted in bold in the table) account for 90% of the accumulated losses. The fiscal impact of loss takeover could be particularly significant in Tamil Nadu, Rajasthan, Madhya Pradesh, Telangana and Uttar Pradesh—where the annual-outgo-to-GSDP ratio ranges from 0.4% to 0.6%. In Andhra Pradesh, the annual power sector takeover burden would be ₹3,300 crore, and this could further strain the already stressed state finances, given the existing FD/GSDP (Fiscal Deficit/ Gross State Domestic Product) ratio of 4.4%. Based on FY24 data, Karnataka and Maharashtra appear to have the fiscal space for loss takeover. However, their fiscal capacities may change if total liabilities are considered. Moreover, both states may face reduced fiscal flexibility in the coming years due to new non-power-sector state government subsidy schemes.

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[50] This applies to bonds issued with 20-year tenors. Coupon rates are based on State Government Securities issued for 20 years after 2021 with a 0.5% spread, and an additional 0.25% spread applied for non-SLR status.

Alternatively, to ease the fiscal impact, the debt takeover could be implemented in tranches. The takeover in each tranche could be made subject to meeting conditionalities stipulated by the state government. With a tranche-wise approach, the annual outgo ranges from ₹15,400 crore in Year 1 to ₹92,425 crore from Year 5 to Year 20.

As seen in Table 21 for 10 states and in Annexure 8 for 22 states, the growing economies of these states enable them to manage the impact on their borrowing capacity although subsequent tranches would also have to address the accumulated interest/carrying cost applicable for the period. This would remain true even after the debt takeover is completed in most states, over a five-year time frame.

Table 21: Impact of loss takeover (tranche-wise) on FD/GSDP[51]

State	FD/GSDP		Impact of loss takeover as % of GSDP					
			Tranches					
	Existing	One-time	Tranche 1	Tranche 1–2	Tranche 1–3	Tranche 1–4	Tranche 1–5	All 5 tranches
	FY24	FY25	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
Unit	%	%	%	%	%	%	%	%
Tamil Nadu	3.4%	0.59%	0.12%	0.22%	0.31%	0.40%	0.47%	0.42%
Rajasthan	4.3%	0.55%	0.11%	0.20%	0.28%	0.34%	0.40%	0.35%
Madhya Pradesh	3.3%	0.52%	0.10%	0.20%	0.29%	0.37%	0.45%	0.41%
Telangana	3.4%	0.46%	0.09%	0.17%	0.25%	0.31%	0.37%	0.33%
Uttar Pradesh	3.1%	0.38%	0.08%	0.16%	0.25%	0.35%	0.45%	0.45%
Kerala	3.0%	0.29%	0.06%	0.11%	0.16%	0.19%	0.23%	0.21%
Haryana	2.9%	0.24%	0.05%	0.09%	0.13%	0.17%	0.20%	0.18%
Andhra Pradesh	4.4%	0.21%	0.04%	0.08%	0.11%	0.14%	0.16%	0.14%
Karnataka	2.6%	0.12%	0.02%	0.04%	0.06%	0.08%	0.09%	0.09%
Maharashtra	2.2%	0.09%	0.02%	0.03%	0.04%	0.05%	0.06%	0.05%

Source: Authors' analysis based on data from (PFC, 2025; RBI, 2024)

Although this analysis focuses on loss absorption, working capital liabilities present an equally critical concern. Given the absence of comprehensive data on working capital borrowings across states, cumulative losses serve as a reasonable proxy for state-level analysis of the fiscal burden.

Using working capital liability data available in eight states, Table 22 compares the variation in impact due to liability takeover with that due to a one-time loss takeover, and Table 23 shows the impact of tranche-wise takeover of liabilities. As working capital borrowing is higher than losses in Andhra Pradesh, Maharashtra and Punjab[52], the impact of liability takeover is greater than loss takeover. However, it is considerably lower in the other states.

[51] The impact is estimated for accumulated losses until FY24 and the annual loss for FY24. It is assumed that the first year of takeover will be FY25 for the purpose of this analysis. For tranche-wise calculation, the GSDP projections are based on past nominal GDSP growth rates for all years since 2011, barring the COVID-19-impacted years of FY21 and FY22. A carrying cost of 9% is assumed for estimating the carried cost on tranches until takeover.

[52] Andhra Pradesh, Maharashtra, and Punjab have significant contingent liabilities that contribute to this discrepancy. While contingent liabilities are not accounted for in reported losses, DISCOMs may still borrow to meet the financial obligations. In Maharashtra, the difference between accumulated losses and working capital borrowing for FY24 is ₹37,601 crore, compared to contingent liabilities of ₹41,035 crore for the same year. Ongoing disputes, particularly around power procurement (₹35,688 crore), are a major contributor to these contingent liabilities

Table 22: Impact of liability takeover on fiscal deficit in eight states

State	Impact of liability takeover on fiscal deficit					
	FD/GSDP (FY24)	Outstanding working capital borrowing FY24	Coupon rate	Annual outgo due to liability takeover from FY25	Annual outgo with liability takeover as % of GSDP (FY25)	Annual outgo with loss takeover as % of GSDP (FY25)
Unit	%	₹ Cr.	%	₹ Cr.	%	%
Andhra Pradesh	4.4%	46,066	8.25%	4,779	0.30%	0.21%
Bihar	4.1%	8,933	7.91%	904	0.09%	0.18%
Haryana	2.9%	7,468	8.22%	773	0.06%	0.24%
Karnataka	2.6%	11,316	8.40%	1187	0.04%	0.12%
Maharashtra	2.2%	73,827	8.01%	7,525	0.16%	0.09%
Punjab	4.3%	10,745	8.22%	1,113	0.13%	0.10%
Rajasthan	4.3%	65,442	8.40%	6,864	0.40%	0.55%
Telangana	3.4%	37,494	7.95%	3,805	0.23%	0.46%

Source: Authors' analysis with data from regulatory orders and petitions as well DISCOM annual audited financial statements/reports, (RBI, 2024)

Table 23: Impact on liability takeover (tranche-wise) on FD/GSDP[53]

State	Impact of liability takeover on fiscal deficit					
	FD/GSDP (FY24)	Outstandin g working capital borrowing FY24	Coupon rate	Annual outgo due to liability takeover from FY25	Annual outgo with liability takeover as % of GSDP (FY25)	Annual outgo with loss takeover as % of GSDP (FY25)
Unit	%	₹ Cr.	%	₹ Cr.	%	%
Andhra Pradesh	4.4%	46,066	8.25%	4,779	0.30%	0.21%
Bihar	4.1%	8,933	7.91%	904	0.09%	0.18%
Haryana	2.9%	7,468	8.22%	773	0.06%	0.24%
Karnataka	2.6%	11,316	8.40%	1187	0.04%	0.12%
Maharashtra	2.2%	73,827	8.01%	7,525	0.16%	0.09%
Punjab	4.3%	10,745	8.22%	1,113	0.13%	0.10%
Rajasthan	4.3%	65,442	8.40%	6,864	0.40%	0.55%
Telangana	3.4%	37,494	7.95%	3,805	0.23%	0.46%

Source: Authors' analysis with data from regulatory orders and petitions as well DISCOM annual audited financial statements/reports, (RBI, 2024)

The analysis demonstrates that the additional fiscal impact of debt takeover through 20-year bonds could be manageable, particularly if issued in tranches with strict conditionalities and measures to prevent future losses. This approach is a more practical and feasible way of addressing accumulated losses than tariff increases.

Because regulatory assets contribute to liabilities and losses—essentially representing deferred tariff increases—SERCs could consider adjusting approved regulatory assets

(MSEDCL, 2024b). In Punjab, while the difference between accumulated losses and working capital liabilities is only 10%, PSPCL has identified ₹11,162 crore as contingent liabilities, exceeding the working capital borrowing reported in FY24 (PSPCL, 2024b). However, this figure may not be attributable solely to the distribution business, as the annual financial statements also include the generation business. For Andhra Pradesh DISCOMs, the extent of contingent liabilities was not explicitly quantified in the annual audited financial statements. also has information on the generation business.

[53] The methodology is similar to that described in Footnote 17.

alongside debt takeover transferred to DISCOM accounts as grants or equity. This would address both the principal amount and interest liability simultaneously. The central government could provide a clear framework to help states implement this approach and benefit consumers. This would be beneficial in states with significant regulatory assets, which need to be addressed in a time-bound manner following recent Supreme Court directions to regulatory commissions to liquidate existing regulatory assets (SCI, 2025).

5.2 Power procurement

It is crucial that states adopt a least cost power procurement and planning approach to meet their growing electricity demand. Although coal-based capacity is vital to India's power mix today and will continue to play a critical role for the foreseeable future, it faces supply uncertainties and price volatility. As discussed earlier, new coal projects require 6–7 years for commissioning and involve capital investments of about ₹8–12 crore/MW.

Renewable energy, particularly solar and wind, offers shorter gestation periods and is available at competitive costs.[54] Solar power has the additional advantage of modularity, requiring lower up-front capital investment than conventional thermal plants on a per megawatt basis.[55] Both renewable resources are fuel-independent, making them inflation-proof over their operational lifetime. However, solar and wind are inherently variable and weather-dependent, with limited round-the-clock availability.

Increasing the share of solar and wind can reduce—or even virtually arrest—the growth of the overall cost of power supply. However, this transition must be managed to ensure that grid reliability is maintained. This requires a multi-pronged approach: existing coal and hydro resources must be operated flexibly based on system requirements; demand-side management initiatives should align consumption patterns with the daily and seasonal availability of renewable energy; and substantial investments in energy storage infrastructure are essential. This is particularly the case in view of the sharp reduction in storage costs over the past two years and the increasing mainstreaming of the technology with some projects being commissioned and several under construction (IESA, 2025). This is detailed in Section 7.3.

Adding coal capacity to meet future demand growth should be considered if it represents the least-cost option for addressing reliability concerns, after exhausting demand-shifting mechanisms and storage investments. This cautious approach is warranted because coal projects require substantial capital investments and likely face lower utilisation in a renewables-dominated future grid. Without careful planning, there is a significant risk of creating stranded assets in the power system, imposing considerable financial costs on state utilities and ultimately on consumers.

MSEDCL's resource adequacy plan for the period from FY26 to FY30 demonstrates the potential cost benefits of increasing the share of renewable energy in the procurement mix (MSEDCL, 2024a). Following regulatory mandates for short-term, medium-term and long-term resource adequacy, Maharashtra became among the first states to publish a supply plan for meeting future electricity demand reliably in FY30. The utility's resource plan projected significant capacity additions between FY25 and FY30: 25,951 MW of solar, 4,344 MW of wind-solar hybrid

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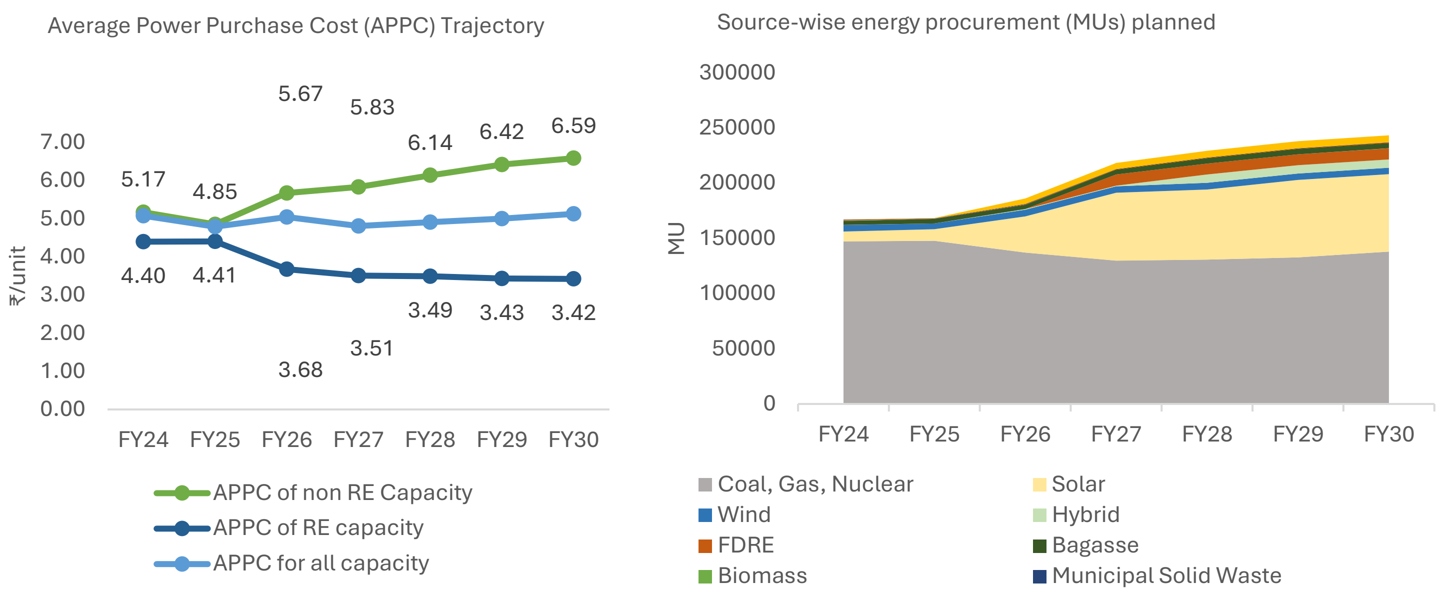
[54] Solar and wind technologies have demonstrated 2–3 year construction timelines and current tariff rates of ₹2.5–3 per unit.

[55] Solar installations offer modular deployment with capital costs of ₹3.5 crore per MW.

projects, 1,468 MW of Firm and Dispatchable Renewable Energy (FDRE), 4368 MW of Distributed RE projects and 4,824 MW of storage. Maharashtra contracted capacity as per the plan to ensure reliable supply provision in the medium term.

In FY24, renewable energy (excluding large hydropower) accounted for 12% of MSEDCL's total power procurement. The overall average procurement cost was ₹5.08 per unit. Based on these planned renewable energy and storage additions, MSEDCL projected that its average power procurement cost would increase by only 0.15% annually between 2024 and 2030 (Figure 4). This contrasts sharply with the utility's historical average power purchase cost escalation of 5.8% per annum between FY18 and FY24

Figure 4: Power procurement mix and cost projected by MSEDCL in Maharashtra until FY30



Source: Authors' analysis of data from (MERC, 2025).

Such cost stabilization represents a notable departure from typical utility cost trajectories across Indian states. The projected cost moderation stems from the differential between renewable and conventional power tariffs. MSEDCL's plan projects that renewable energy and storage from contracted sources will be available at an average of ₹3.68/kWh by 2030, compared to ₹6.15/kWh for non-renewable sources.

CEA has conducted resource adequacy studies to estimate future supply requirements across 31 of 35 states and union territories. According to CEA's study for Madhya Pradesh in FY24, the state is projected to add 18,743 MW of solar capacity, 4,895 MW of wind capacity and 6,119 MW of storage systems (CEA, 2024). This renewable energy expansion would enable approximately 40% of the state's demand (excluding hydro) to be met through clean energy sources. Despite this significant renewable capacity addition, overall power costs are projected to increase at 5% per annum from FY24 to FY30. This cost escalation stems from the plan's proposal to add 5,945 MW of new coal-based capacity. Notably, despite this substantial capacity addition, coal-based generation is expected to increase by only 7,618 MU. Assuming existing coal plants generate as before, this implies that the increased capacity of 5,945 MW has an annual average plant load factor of 15% resulting in an annual average plant load factor of merely 15%—indicating underutilization of these new assets. The financial implications of this capacity planning approach are significant. DISCOM power purchase costs are projected to increase by ₹10,800 crore by 2030,[56] primarily driven by fixed cost obligations for the new coal capacity.

5.3 Solarisation of agriculture

A critical approach to integrating large amounts of low-cost solar energy involves aligning agricultural power supply with solar generation hours. This approach can also fundamentally alter the economics of agricultural power supply. In coal-dominated systems, off-peak pricing traditionally occurred during late night hours, leading states to restrict heavily subsidised agricultural supply to these periods. However, with low-cost solar power now available, day-time supply costs are 30–40% lower than average costs. Recognising this economic shift, states such as Gujarat and Maharashtra have begun aligning agricultural power supply hours with solar generation periods, and similar initiatives are emerging across other states (see Annexure 9).

This approach creates unprecedented opportunities for addressing one of India's most intractable fiscal challenges. Agricultural consumers, who represent only 25% of average DISCOM sales, receive 90% of state government electricity subsidies. Solar power is currently available at under ₹3–3.5 per unit whereas average state power procurement costs (including transmission charges and losses) were approximately ₹5.46 per unit in FY24, representing cost savings of 36% to 45%. Although overall DISCOM procurement costs face upward pressures from multiple factors, solar-based agricultural supply could lock-in cost savings and reduce subsidy outflows for 25 years.

Over the past two decades, many states have implemented agricultural electricity supply management measures to curtail groundwater overuse, improve load management, and limit subsidy expenditure. Such demand management measures are prerequisites for aligning agricultural supply with 6–8 hours of solar generation. Under these measures, DISCOMs provide agricultural supply for 10 hours or less: 8 hours in Maharashtra, 7 hours in Karnataka and Rajasthan, 9 hours in Andhra Pradesh and 10 hours in Madhya Pradesh and Uttar Pradesh. Bihar extends supply up to 16 hours, while Tamil Nadu and Telangana have not adopted such demand management measures (PEG 2020).

Three implementation options are available for aligning agricultural demand with solar supply hours:

Option 1 – Centralised Solar Procurement: DISCOMs dedicate contracted solar capacity to meet agricultural demand during solar hours through competitive procurement processes. This capacity can be located anywhere in the country. For example, Andhra Pradesh DISCOMs have contracted 7,000 MW through SECI to provide reliable daytime supply to all farmers by 2026.

Option 2 – Solar Feeder Approach (Decentralised MW-scale deployment): This approach offers the highest cost savings by installing MW-scale solar capacity at tail-end locations dedicated to agricultural feeders, reducing transmission costs and losses (which are applicable in Option 1). Private developers install and maintain plants through competitive bidding, ensuring deployment at scale with competitive pricing. MSEDCL contracted about 16,000 MW in a span of 9 months with this approach to meet almost all of its agricultural demand. This is evidence for the rapid scalability of this model, which is discussed in greater detail in Section

[56] As per the CEA Resource Adequacy study, the cost per megawatt of coal capacity to be added is ₹8.24 crore/MW. The annualized cost based on the MYT regulations of the Madhya Pradesh Electricity Regulatory Commission works out to about ₹10,800 crore by 2030.

5.3. In fact, MSEDCL's projections for cost reductions discussed in Section 5.2 is also based on this rapid solar capacity addition for agriculture. However, segregation of agricultural demand from other rural demands through physical/virtual separation of feeders is a critical prerequisite for this model.

Option 3 – Individual Solar Pumps: Direct provision of solar-powered pumps to farmers faces significant operational challenges such as maintenance difficulties across dispersed locations, substantial capital subsidy requirements and the requirement of farmer capital investment contribution, leading to exclusion (BTI, 2022). Although farmers benefit from reliable supply, particularly where solar pumps replace diesel sets, this approach may not achieve subsidy savings for state governments and remains challenging to scale effectively. It would also require significant and onerous monitoring (Gupta, 2019; Upadhyay, Rathod, & Sakariya, 2019).

Options 1 (Centralised solar procurement) and 2 (Solar feeder approach) represent the most viable pathways for rapid scaling, cost reduction, and subsidy savings. However, successful implementation requires two critical prerequisites: (1) robust transmission and distribution networks for reliable supply and (2) the ability to limit agricultural power supply to solar hours. To reap Option 2's substantial benefits, DISCOMs must physically or virtually segregate agricultural load from other rural loads, ideally through dedicated agricultural feeders.

Nine states—Gujarat, Maharashtra, Telangana, Tamil Nadu, Rajasthan, Madhya Pradesh, Haryana, Punjab and Andhra Pradesh—account for 90% of agricultural electricity consumption in India. Six of these states have significant feeder segregation under various schemes over the past two decades. Three states—Telangana, Tamil Nadu and Andhra Pradesh—currently lack adequate segregation but are actively undertaking separation efforts. Bihar and Uttar Pradesh, where agricultural consumption is rapidly growing with recent pumpset electrification, have initiated feeder segregation under the centrally sponsored RDSS and DDUGJY schemes, targeting 100% segregation by 2026.

The 12 states shown in Table 24 account for 97% of India's agricultural power consumption. If 50 to 70% of the consumption in these states transitions to solar power through Option 2 (Solar feeder approach) by 2032, the resulting cost savings would range from ₹77,000–₹90,000 crore annually. In Table 22, the savings of ₹77,558 crore are calculated assuming solar tariffs of ₹3.5 per unit. This can increase to ₹90,000 crore with solar tariffs of ₹3 per unit. The calculation is assuming the average DISCOM power purchase cost (including transmission) increases at 2% per annum. This is a conservative assumption because in these states historical growth rates of power purchase are much higher, ranging from 2.7% to 6.4% per year.

Table 24: State-specific savings from adoption of feeder-level solarisation approach[57]

State/ UT	**Agricultural consumption in FY32**	**Average power purchase cost (including Transmission cost)**		**State transmission losses**		**Cost of grid supply at sub-station (FY32)**	**Savings due to solar feeder approach (FY32)**	**% of AG sales solarised by FY32**	**Annual savings in FY 32**
		FY24	**FY32**	**FY24**	**FY32**				
Units	MU	₹/kWh		%		₹/kWh		%	₹ Cr.
Rajasthan	57,535	5.07	5.9	3.50%	3.4%	6.15	2.65	70%	10,668
Maharashtra	50,869	5.61	6.6	3.50%	3.4%	6.80	3.30	85%	14,284
Madhya Pradesh	42,703	4.98	5.8	3.50%	3.4%	6.04	2.54	70%	7,591
Uttar Pradesh	37,806	5.59	6.5	3.50%	3.4%	6.78	3.28	70%	8,679
Telangana	31,284	6.19	7.3	3.50%	3.4%	7.51	4.01	50%	6,268
Gujarat	28,941	5.45	6.4	3.50%	3.4%	6.61	3.11	70%	6,300
Karnataka	27,772	6.45	7.6	3.50%	3.4%	7.82	4.32	70%	8,403
Tamil Nadu	19,843	6.13	7.2	3.50%	3.4%	7.43	3.93	50%	3,903
Andhra Pradesh	12,946	6.29	7.4	3.50%	3.4%	7.63	4.13	70%	3,741
Haryana	13,644	5.42	6.4	3.50%	3.4%	6.57	3.07	70%	2,935
Punjab	15,618	4.48	5.2	3.50%	3.4%	5.43	1.93	70%	2,113
Chhattisgarh	11,643	5.59	6.5	3.50%	3.4%	6.78	3.28	70%	2,673
Total for 12 states	**3,50,605**		**6.50**						**77,558**

Source: Author's analysis based on data from (PFC, 2025; CEA, 2022; CEA, 2024a; PEG, 2025)

The potential for savings even before FY32 is substantial with phase-wise implementation such that 10–20% of agricultural consumption could be solarised by FY27, and so on, until the 50% or 70% target is achieved in FY32. Between FY27 and FY32, such an approach could deliver cumulative savings of ₹2.68 lakh crore, as detailed in Table 25.[58]

[57] The average power purchase cost (including transmission) for FY24 was as reported by PFC in the report on the performance of power utilities (PFC 2025). The escalation rates for agricultural demand are as estimated by CEA in the 20th *Electric Power Survey* (EPS) (CEA, 2022). The actuals for agricultural consumption as reported by CEA for all utilities for 2023 in the Annual General Review was used for the projections (CEA, 2024a). State transmission losses were assumed based on losses reported in tariff orders in various states for FY24 (PEG, 2025d). The trajectory for solarisation is an input or assumption based on the current status of feeder segregation, the presence of policies to align agricultural supply with solar availability and existing progress under various schemes towards agricultural solarisation in states.

[58] These projections are based on the conservative assumption that the discovered solar tariff is ₹3.5 per unit throughout the deployment period (despite historical declining cost trends). The actual savings potential is likely higher given the continued downward trajectory of solar costs and the potential for faster implementation if appropriate policy support is provided.

Table 25: Year-wise savings with solarisation

Year-wise savings with solarisation approach							
State	FY27	FY28	FY29	FY30	FY31	FY32	Total
	₹ Cr.	₹ Cr.	₹ Cr.	₹ Cr.	₹ Cr.	₹ Cr.	₹ Cr.
Rajasthan	1,612	2,755	4,178	5,931	8,072	10,668	33,216
Maharashtra	9,526	10,351	11,236	12,183	13,198	14,284	70,778
Madhya Pradesh	1,286	2,149	3,185	4,420	5,878	7,591	24,509
Uttar Pradesh	687	1,549	3,053	4,908	7,174	8,679	26,050
Telangana	417	906	1,476	2,668	4,050	6,268	15,785
Gujarat	1,198	1,953	2,829	3,836	4,988	6,300	21,104
Karnataka	1,689	2,721	3,895	5,224	6,721	8,403	28,653
Tamil Nadu	261	566	922	1,665	2,524	3,903	9,841
Andhra Pradesh	725	1,177	1,697	2,292	2,971	3,741	12,603
Haryana	559	912	1,320	1,789	2,325	2,935	9,840
Punjab	412	671	967	1,305	1,686	2,113	7,154
Chhattisgarh	443	743	1,105	1,540	2,059	2,673	8,563
Total	**18,814**	**26,452**	**35,862**	**47,761**	**61,647**	**77,558**	**2,68,096**

Source: Author's analysis based on data from (PFC, 2025; CEA, 2022; CEA, 2024a; PEG, 2025)

Option 3 (Individual Solar Pumps) remains important for areas where Options 1 and 2 are not feasible due to poor networks and the inability to limit supply hours, though it is challenging to scale and less cost-effective.

For decentralised solar deployment under Options 2 and 3, 30% capital subsidy is provided under the centrally sponsored PM-KUSUM (*Pradhan Mantri Kisan Urja Suraksha evam Utthaan Mahabhiyan*) Scheme. Further, 60% to 90% capital subsidy is provided under the RDSS scheme to segregate agricultural feeders for solarisation on priority. Such support should be extended for an additional five years to ensure rapid adoption at scale.

5.4 AT&C loss reduction

As mentioned in Chapter 2, AT&C loss reduction was identified as a priority in almost all schemes aiming to address financial challenges in the sector for the past three decades. Additionally, in the same time frame, several centrally sponsored schemes have been implemented to establish robust and well-functioning networks and improve metering and billing, with the explicit aim of reducing AT&C losses. Given the focus on AT&C loss reduction, India has been reporting significant improvements over the years. National AT&C losses were 24.16% and 16.12% in FY14 and FY24, respectively, showing an 8 percentage point reduction in a decade. In FY14, 10 states[59] reported losses of about 40% or more, but only three states reported losses higher than 40% in FY24.[60]

This indicator, long considered a dip-stick indicator of the level of operational performance of DISCOMS, has two critical components:

[59] Bihar, Odisha, Meghalaya, Tripura, Jharkhand, Sikkim, Arunachal Pradesh, Manipur, Nagaland and Jammu and Kashmir.
[60] Arunachal Pradesh, Nagaland and Jammu and Kashmir

— <u>Distribution network losses:</u> This component measures the difference between the energy input in the DISCOMs network and the actual sale to consumers. High distribution losses are due to technical inefficiencies in the electricity infrastructure (long lines, undersized conductors, overloaded transformers and feeders) as well as poor metering and power theft.
— <u>Collection efficiency:</u> This component captures the revenue actually collected from consumers as compared to the revenue billed, indicating the extent of outstanding receivables from consumers. Such commercial losses are due to poor billing systems, inefficient revenue collection processes, poor governance processes and weak enforcement mechanisms.

5.4.1 Impact of reducing distribution losses

Distribution losses in the power sector can be effectively addressed through capital investments in infrastructure; network augmentation, including conductor replacement; substation modernisation; and improvements in metering coverage and accuracy. Several states have demonstrated significant loss reduction primarily attributable to such capital works over the past decade. Notable successes include Bihar DISCOMs, which recorded a substantial 28.04 percentage point reduction in distribution losses: from 44% in FY14 to 15.96% in FY24. Similarly, West Bengal achieved a 16 percentage point improvement, with losses decreasing from 32% in FY14 to 16.25% in FY24.

The all-India average distribution loss reduction rate between FY14 and FY24 stood at 0.74 percentage points per annum. Under a scenario assuming a much higher annual reduction rate of 1.15 percentage points per year—achievable through intensified infrastructure investments and operational improvements—the national average distribution losses for FY24 would have been approximately 12% instead of the actual 13.21%, thereby meeting the national target established under RDSS.

At the state level, the distribution loss reduction targets would be differentiated based on current performance levels: states with losses below 10% would target lower reductions of 0.5% per annum, while higher-loss states would pursue more aggressive targets in a graded manner—with states experiencing losses between 25% and 30% targeting reductions of 2.5% per annum, and states with even greater losses targeting proportionally higher targets.

Under this accelerated loss reduction scenario, assuming that half of the loss reductions translate to reduced power purchase costs while the other half generates increased revenue, the estimated annual cost savings for FY24 would amount to ₹10,049 crore nationally. These savings represent approximately 1% of annual DISCOM costs. The state-wise savings represented as a percentage of annual costs are shown in Table 26. Notably, there is little potential for additional cost reduction in states with high accumulated financial losses such as Andhra Pradesh, Tamil Nadu and Telangana, where potential savings are estimated at about 0.5% of total annual expenses. Maharashtra, Uttar Pradesh, Rajasthan and Madhya Pradesh have savings of more than ₹1,000 crore, but even this is less than 1–2% of the total expenses in a year.

Table 26: State-wise savings with targeted/ scenario distribution loss reduction

Reduction in total expenses with distribution loss reduction	Number of states	List of states
Less than 0.5%	5	**Andhra Pradesh**, Gujarat, Kerala, **Tamil Nadu, Telangana**
0.5–1%	6	Assam, Haryana, Himachal Pradesh, Karnataka, Manipur, Punjab
1–1.5%	7	Bihar, Chhattisgarh, **Maharashtra**, Meghalaya, Rajasthan, **Uttar Pradesh**, Uttarakhand
1.5–2%	4	Jharkhand, **Madhya Pradesh**, Tripura, West Bengal
2–3%	2	Mizoram, Sikkim
>4%	2	Nagaland, Arunachal Pradesh

Source: Authors' analysis based on data from (PFC, 2025).

The key takeaway from the analysis in this section is that reported distribution losses are already quite low in many states, and future reductions would require substantial investment with diminishing incremental benefits or cost savings compared to previous years. However, this must be considered alongside the fact that distribution losses of DISCOMs are often underreported due to inadequate metering of agricultural consumers, who are frequently unmetered or poorly metered. DISCOMs and regulatory commissions typically estimate such consumption for these consumers on a normative basis rather than on the basis of actual meter readings. This creates opportunities for misreporting, because DISCOMs may inflate agricultural or unmetered sales figures to artificially reduce reported distribution losses to meet performance trajectories. This practice masks the true extent of system inefficiencies. Underreporting occurs primarily in states with large agricultural demand and those with unmetered or poorly metered residential consumers.

Maharashtra provides evidence of the scale of this issue: a working group appointed by the state electricity regulatory commission reassessed agricultural demand using automatic meter readings from feeders dedicated to agricultural consumers. The working group's analysis led to reduction of estimated agricultural consumption by 7,316 MU for FY19. [61] This led to a revision in distribution losses from the reported 14.7% to 20.5% for FY19, an increase of 5.8 percentage points (MERC, 2020). Because similar underestimation of sales or overestimation of loses may occur in other states, the deployment of communicable/ smart meters with automatic reading capabilities on DISCOM feeders and the use of such recorded data to assess agricultural consumption is critical. Smart metering for feeders and distribution transformers is an explicit objective under the RDSS scheme, which provides the policy framework and funding mechanism to address these measurement gaps. Loss reduction based on re-estimated numbers could result in higher loss reduction targets, requiring substantial investment to address challenges. However, it could also result in substantial savings.

5.4.2 Potential future cost reduction due to reduction in outstanding receivables

Timely revenue collection represents a critical component of AT&C losses, measured through collection efficiency: the ratio of revenue collected in a given year (including recovery of previous years' arrears) to revenue billed in that year. Collection efficiency exhibits significant

[61] The working group estimated agricultural sales for FY19 at 23,500 MUs when MSEDCL claimed sale of 32,696 MU. Based on the analysis of the working group, the Commission approved 25,380 as the sales resulting in a reduction of 7,316 MUs of agricultural sales (MERC, 2020).

variation across states and consumer categories, occasionally exceeding 100% when past arrear recoveries surpass current year's under-recoveries (CEA, 2023a). Consequently, outstanding receivables provide a more reliable indicator of collection efficiency.

To minimise dependence on working capital borrowing, receivable days should not exceed 45 days, aligning with standard payment cycles for power procurement. However, only 7 of 25 states achieved this benchmark in FY24. Nine states recorded receivable days exceeding 100 days, with Madhya Pradesh at 166 days and Bihar, Jharkhand, Maharashtra, Telangana and Uttar Pradesh each reporting over 200 days (PFC, 2025).

For the 18 states where receivable days exceed 45 days, achieving the target of 45 days through improved revenue recovery and arrear management would eliminate the need for working capital loans to ensure timely payments to generators and other utilities. Had this target been achieved in FY24, DISCOMs would have realised interest cost savings of ₹9,869 crore.[62] Even halving current receivables would generate savings of ₹6,212 crore, equivalent to 0.76% of total expenses in the states with high receivables and 0.67% of national DISCOM expenses. This is detailed in Table 27.

Table 27: State-wise savings if receivable days reduces by half or 45 days, whichever is lower

State	Receivables (days)	Savings (Cr.) if receivable days reduces by half or 45 days, whichever is lower	Expenses (Cr.)	% of total expenses
Andhra Pradesh	110	275	67,086	0.41%
Assam	50	2	10,418	0.02%
Bihar	233	329	32,266	1.02%
Chhattisgarh	96	67	23,617	0.28%
Haryana	56	14	41,140	0.03%
Jharkhand	286	207	12,313	1.68%
Karnataka	54	19	76,645	0.02%
Kerala	46	1	22,508	0.00%
Madhya Pradesh	166	282	58,914	0.48%
Maharashtra	200	1,475	1,24,954	1.18%
Manipur	391	31	944	3.24%
Meghalaya	195	16	1,904	0.86%
Punjab	89	77	43,164	0.18%
Tamil Nadu	58	33	1,00,080	0.03%
Telangana	220	826	65,672	1.26%
Tripura	86	4	2,074	0.19%
Uttar Pradesh	310	2,534	1,04,357	2.43%
West Bengal	60	19	34,282	0.06%
Total for states		**6,212**	**8,22,338**	**0.76%**
National total		**6,212**	**9,98,284**	**0.62%**

Source: Authors' analysis based on data from (PFC, 2025).

Realising and sustaining these savings requires consistent annual efforts, including investment in collection processes, improvements in supply and service quality, and trust-building with consumers.

However, such receivable reduction may not be feasible without state government intervention through arrears takeover and receivables provisioning. As highlighted in Chapter 2, approximately 40% of outstanding receivables in states with the highest receivables are over

[62] Assuming an annual 9% rate of interest.

three years old, and 52% are over two years old, indicating structural and legacy collection challenges that require policy intervention beyond operational improvements.

Takeover of arrears aged more than two years by state governments for the five states that account for 75% of total receivables in India would amount to ₹96,422 crore. This intervention alone would reduce average receivable days for these five states by 22%—from 139 days to 108 days—but would require substantial fiscal support. State-level details for the five states are presented in Table 28.

Table 28: Impact of take-over of outstanding receivables older than two years

State	Receivables FY24	Share of receivables aged above 2 years	Outstanding receivables FY24	Outstanding receivables after state takeover of aged receivables	Quantum of state takeover	Outstanding receivables after state takeover of aged receivables
Unit	Days	%	₹ Cr.	₹ Cr.	₹ Cr.	Days
Uttar Pradesh	310	64%	66,308	23,871	42,437	127
Telangana	220	53%	30,461	14,317	16,144	126
Maharashtra	200	38%	59,808	37,081	22,727	130
Karnataka	54	35%	8,567	5,569	2,998	50
Andhra Pradesh	110	58%	20,283	8,519	11,764	67
Total for five states	**139**	**52%**	**1,85,427**	**89,005**	**96,422**	**108**

Source: Authors' analysis based on data from (PFC, 2025).

The analysis demonstrates that substantial progress has been achieved in AT&C loss reduction over the past decade. However, sustaining this trajectory will require continued investments in infrastructure, systematic process improvements and active state government support. Although these efforts produce meaningful benefits, the potential annual savings are modest compared to alternative cost reduction strategies such as agricultural solarisation and optimisation of power procurement operations and planning.

The combined impact of a 1.15% reduction in transmission losses and halving outstanding receivables would generate annual savings of ₹16,260 crore based on current reported data for FY24. Such efforts translate to a 1.6% reduction in cost for DISCOMs on average. This highlights that although AT&C loss reduction remains important for operational efficiency and financial sustainability, the gains from this reduction are not sufficient to address the financial challenges facing DISCOMs. DISCOMs and state governments should prioritise a comprehensive approach that integrates multiple cost optimisation and revenue recovery strategies to achieve transformational improvements in the power sector's financial health.

5.5 Cost-reflective tariffs

As established in Chapter 2, aligning DISCOM revenues with expenses recognised by the regulator, is fundamental to sustainable distribution operations. Cost-reflective pricing ensures that DISCOMs recover prudent operational and capital costs, laying the financial foundation for reliable service delivery. Equally important, this alignment creates efficiency incentives and accountability mechanisms through multiple channels: public accountability and political scrutiny of tariff increases compel DISCOMs' to demonstrate cost prudence and efficiency improvements, while tariff increase would also make alternative supply options such as open access and captive generation more economically viable, introducing competitive pressure on DISCOM performance. The following measures towards cost-reflective tariffs can be explored by DISCOMs.

5.5.1 Inflation-linked tariff mechanism: A framework for tariff certainty

A systematic approach to ensuring timely and appropriate tariff adjustments is to implement an inflation-indexed tariff mechanism. This framework provides regulatory certainty, maintains efficiency incentives and ensures timely cost recovery while protecting consumers from arbitrary tariff increases.

From 2016 and 2023, DISCOMs in 22 states accumulated a massive aggregated revenue shortfall of ₹7.66 lakh crore, including interest costs. This gap has been widening by an average of 11% each year since 2016. In 2016, it cost these DISCOMs ₹7.02 on average to supply each unit of electricity, but these DISCOMs received ₹6.02 per unit (including government subsidies), creating a revenue gap of ₹1 per unit sold. Since then, the situation has worsened because costs have risen faster than revenues. Electricity tariffs increase by 3.2% annually from 2016 to 2023 was not sufficient to bridge the revenue gap as supply costs increased by 3.46% annually. Meanwhile, interest on the accumulated losses averaged 10% per year. This mismatch between cost increases and tariff adjustments explains why the revenue gap continues to grow despite some tariff increase.

A scenario was analysed where instead of a 3.2% tariff increase between FY15 and FY16, an average tariff increase of 10% was considered to account for inadequate tariff increases in previous years. As no UDAY debt takeover is assumed in this scenario for this year, the additional tariff increase was required in the first year to bridge the significant revenue gap and address build-up of legacy costs until 2016.

Post this correction in the scenario, an annual increase is considered for subsequent years to account for the prevailing tariff rate and the tariff increase required to meet expenses on average. This translates to an annual escalation rate varying by *state from -1% to 4.5%*. However, going forward, the tariff increase required may not be significant given regular past tariff increases as well as potential cost reduction with increased renewable energy procurement and progress with agricultural solarisation.

Under this approach, higher revenue from regular tariff increases would reduce the total revenue gap by ₹4.41 lakh crore over the period, or save DISCOMs approximately ₹60,000 crore per year. These savings would also eliminate ₹1.6 lakh crore in interest costs during this period. The scenario assumes an average tariff increase of 3.9% across all 22 states between FY16 and FY23, which is only 0.7 percentage points higher than actual increase observed in this period. Despite this small difference, regular and predictable tariff increases would create much more stable and certain pricing for consumers. Table 29 shows the impact on individual states.

Table 29: State-specific savings with inflation-linked tariff approach

State	Escalation rate considered	Cumulative revenue gap (₹ Cr.)			Savings in interest cost
		Actual	Scenario	Savings	
	%	₹ Cr.	₹ Cr.	₹ Cr.	₹ Cr.
Andhra Pradesh	4.5%	-43,289	-49,722	-6,433	837
Assam	4.5%	-7,545	-6,518	1,027	212
Bihar	3.5%	-32,966	7,904	40,870	14,279
Chhattisgarh	4.5%	-11,311	-7,315	3,996	-319
Gujarat	2.2%	-5,263	19,223	24,486	11,576
Haryana	-2.0%	-4,219	13,503	17,722	7,967
Himachal Pradesh	2.0%	-4,719	2,139	6,858	1,951
Jharkhand	4.5%	-20,673	-17,347	3,326	1,355
Karnataka	4.5%	-30,132	-41,537	-11,405	-1,814
Kerala	4.5%	-8,284	1,913	10,197	3,848
Madhya Pradesh	4.5%	-57,775	-56,344	1,431	-113
Maharashtra	4.5%	-95,496	-76,502	18,994	6,520
Manipur	4.5%	-1,870	-573	1,297	328
Meghalaya	4.5%	-2,728	-1,121	1,607	387
Punjab	4.5%	-20,418	12,278	32,696	10,025
Rajasthan	4.5%	-83,679	-66,299	17,380	4,671
Tamil Nadu	4.5%	-1,40,403	4,220	1,44,623	52,686
Telangana	4.5%	-73,427	-30,181	43,246	15,600
Tripura	4.5%	-864	-3,048	-2,184	-868
Uttar Pradesh	4.5%	-95,425	-34,671	60,754	22,518
Uttarakhand	4.5%	-5,728	-3,092	2,636	1,084
West Bengal	4.5%	-20,105	8,151	28,256	8,008
National Level	**3.9%**	**-7,66,319**	**-3,24,937**	**4,41,382**	**1,60,740**

Source: Analysis based on data from PFC Report on Performance of Power Utilities for multiple years

The evidence strongly supports implementing inflation-indexed tariffs. However, it is crucial that automatic tariff increases and cost recovery do not compromise accountability for DISCOM performance and efficiency improvements. To address this, the following approach is proposed:

— State electricity regulatory commissions establish cost trajectories and performance efficiency benchmarks for each DISCOM during five-year control periods.

— Based on approved cost and performance plans, commissions determine fixed annual efficiency factors for each DISCOM, reflecting the expected operational improvements and meeting of performance targets.

— CERC or RBI announces sector-specific or economy-wide inflation rates based on inflation expectations, with announcements made either annually or covering the entire control period

— **Annual tariff revisions occur automatically using the declared inflation rate adjusted by the DISCOM-specific efficiency factor stipulated by the SERC for the control period**

— Unforeseen increases in prudent costs, particularly fuel and power purchase costs, are addressed through fuel surcharge mechanisms in the proposed structure. However, levy of surcharges requires strict regulation and prudence check to ensure DISCOM accountability for performance efficiency.

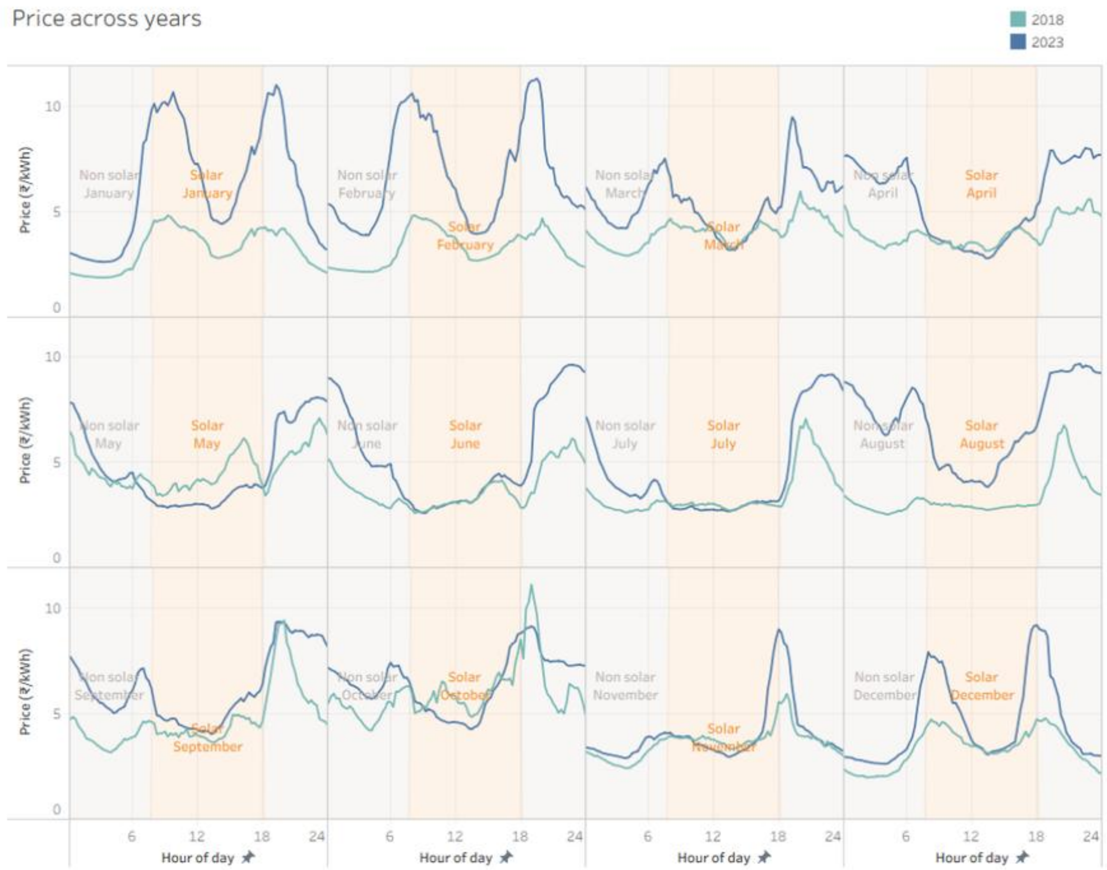
— Surplus revenue at the end of control period is systematically adjusted through future cost recovery mechanisms or tariff reductions, ensuring appropriate gain and loss sharing between utilities and consumers.

This mechanism ensures that tariffs reflect nominal cost increases while incentivising continuous efficiency improvements.

5.5.2 Time-of-day (ToD) tariffs to reflect changes in demand and supply profiles

ToD tariffs and peak pricing for electricity have been implemented for decades by some DISCOMs, especially for industrial and commercial consumers with substantial demand (CEA, 2013). For years, peak pricing was primarily driven by demand considerations, because supply profiles were relatively flat due to dependence on coal-based power. However, with the increasing share of renewables—particularly low-cost solar power—peak demand periods, which occur during daytime solar hours, no longer coincide with peak price periods. This shift is evident from pricing trends in day ahead market contracts traded on India's power exchanges. Between FY18 and FY23, there has been a sharp reduction in prices between 8 am and 6 pm during solar hours. Additionally, there has been a pronounced increase in prices in non-solar hours between 4 am and 8 am as well as between 6 pm and 12 am. This reduction during solar hours and the pronounced morning and evening peaks are particularly evident during non-monsoon months, indicating seasonal price variations as well (Figure 5).

Figure 5: Hourly variation in average day ahead market price (FY18 versus FY23)



Source: Data from IEX, which accounts for more than 95% of total trade in the day ahead market.

These prices in the power exchange are indicative of marginal cost trends across DISCOMs in recent years.[63] This implies that peak prices would certainly occur during non-solar hours, making it critical to understand the demand served by non-solar sources and their variation and associated cost throughout the day.

Further, because electricity demand is quite inelastic and reliability concerns remain paramount for consumers during periods when low-cost solar is unavailable, demand cannot be shifted with pricing incentives alone. Thus, ToD tariff redesign assumes greater importance for achieving cost-reflective tariffs and revenue recovery for DISCOMs.

The MoP notified Electricity (Rights of Consumers) Amendment Rules, 2023, which stipulates that ToD tariffs will apply to all C&I consumers with maximum demand exceeding 10 kW from April 2024 and to other consumers by April 2025. The applicable ToD tariffs should provide at least a 20% rebate during provided solar hours, while peak surcharges should be at least 20% for C&I consumers and at least 10% for other consumers (MoP, 2023). However, despite this policy push, strong economic imperatives and demand from consumers, ToD tariffs levied in many states do not reflect variation in marginal or average hourly/seasonal costs. This is detailed in Annexure 10.

Ideally, for timely cost recovery, ToD tariffs should be applied to a wide range of consumers. However, such tariffs are presently not extended to LT consumers in many states, perhaps due to concerns regarding appropriate metering infrastructure and energy accounting capabilities. In FY25, only 11 of the 24 states levy ToD tariffs on some LT consumer categories. With smart metering deployment, slot-wise accounting should become feasible for a broader consumer base.

5.5.3 Fuel adjustment charges

Fuel surcharge mechanisms enable DISCOMs to recovery additional cost increase due to controllable factors on a quarterly or monthly basis, ensuring timely revenue recovery before the formal regulatory true-up process. This approach reduces working capital requirements and benefits consumers by eliminating carrying costs associated with delayed recovery.

Most states have a regulatory framework for levy of fuel surcharge. The notable exception is Tamil Nadu. Despite enabling regulations, policy emphasis in the National Tariff Policy and promotion under the UDAY, FRP and RDSS programs—reinforced through the notification Rule 14 of the Electricity (Amendment) Rules 2022, regular fuel surcharge levy is practiced by only a few states.

A web-based survey of commercial circulars and fuel surcharge orders conducted for this study reveals that DISCOMs in only eight states[64] levied fuel surcharges in FY23. Further, between January 2024 and April 2025, DISCOMs in 13 states[65] levied fuel surcharge at least once. This

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[63] A study commissioned by the Rajasthan Electricity Regulatory Commission showed that average solar hour costs were 5% to 10% lower than average procurement cost in FY23 and evening peak period costs were 5% to 20% higher. The night period, typically between 10 pm to 4 am when demand is relatively lower, is also a peak price period with costs 5% higher than average in FY23. With more renewable energy procurement by FY30 such that 43% of consumption is from renewables, the cost variation intensifies. Solar hour costs are 15% to 25% lower than average, and evening peak prices are 14% to 25% higher. The costs between 10 pm and 4 am are 6% to 20% higher (PEG, 2024)

[64] Gujarat, Maharashtra, Chhattisgarh, Karnataka, Rajasthan, Assam, Haryana and Madhya Pradesh.

[65] In 2025, Gujarat, Chhattisgarh, Haryana, Karnataka, Rajasthan, Madhya Pradesh and Maharashtra, states which levied fuel surcharge in FY23, continue to do so in this period. However, there is no evidence of fuel surcharge levy in

evidence is based on public notifications of levy rather than on examination of consumer bills across states. As per the analysis, regular implementation occurs only in Chhattisgarh, Madhya Pradesh, Gujarat and Maharashtra, with other states applying surcharges sporadically.

A comprehensive tariff framework integrating inflation-indexed tariffs, ToD pricing and regular fuel surcharge adjustments could significantly strengthen the financial health of DISCOMs. Over time, enhanced market participation, improved energy accounting, and advanced metering infrastructure would enable more dynamic electricity pricing that accurately reflects DISCOMs' true supply costs.

Key takeaways

— Addressing the challenges facing DISCOMs requires a systematic resolution of outstanding losses and liabilities, improvements in power procurement planning to meet reliability requirements through least-cost approaches, strengthening revenue collection frameworks and implementing cost-reflective tariff structures.

— Addressing losses through future tariff increases alone is not feasible because recovery of current outstanding losses over a 10-year period would require additional tariff increases exceeding 18% in six states and 10–15% in five others (beyond the 4% needed for cost escalation). Further, this may not be legally feasible if losses consist of costs disallowed from recovery by the regulator.

— Therefore, takeover of liabilities by the state government through issue of bonds is essential. The bonds could be 20-year bonds, and the takeover could be phased into five tranches to manage the fiscal impact. Takeover under each tranche could be subject to strict conditionalities specified by the state government. In the absence of comprehensive data on liabilities, the impact of loss takeover with such an approach was estimated at ₹70,000 crore annually with a one-time takeover in 22 states.

— With a tranche-wise approach, the annual national impact ranges from ₹15,400 crore in Year 1 to ₹92,425 crore from Year 5 to Year 20. The fiscal impact varies from 0.02% to 0.45% of GSDP in the 10 states which account for 90% of accumulated losses, indicating how fiscal impact can be managed with GSDP growth.

— Preventing future losses requires proactive cost reduction measures through renewable energy addition (wind and solar) with flexible operation of existing coal and hydro resources, demand-side management initiatives, and strategic energy storage investments. New coal investments should only be considered when coal is demonstrably identified as the least-cost option for reliable power supply, given the high investment requirements and the risk of low future utilization.

— Agricultural solarisation, especially through centralised procurement or MW-scale feeder-level procurement, offers possibilities of integrating low-cost solar, reducing the cost of supply and state government subsidy bills while providing farmers with reliable daytime supply. If solarised agricultural feeders supply 50–70% of farmers by 2032, the annual cost and subsidy savings would range from ₹77,000 crore to ₹90,000 crore. However, a crucial prerequisite is that agricultural supply hours should be aligned with solar generation hours. This is achievable in many states given that the existing supply hours are less than 10 hours and that there are ongoing investments in feeder segregation under central and state schemes.

Assam. In addition, to these seven states, Himachal Pradesh, Jharkhand, Kerala, Uttarakhand, Goa and Andhra Pradesh also levied fuel surcharge. It is hoped that such levies continue on a regular basis in these states

- Demonstrable improvements in AT&C loss reduction have occurred in the past decade due to improvements in collection efficiency and lower distribution losses. The combined impact of 1.15% additional distribution loss reduction beyond FY24 levels and halving outstanding receivables would generate ₹16,260 crore in annual savings. This translates to an annual cost savings of 1.6% of annual DISCOM expenses. However, the improvements would require sustained and substantial capital investment to reduce distribution losses. Further, improvement in collection efficiency is constrained because 52% of ₹96,422 crore in receivables is over two years old and likely unrecoverable without state intervention. With distribution losses reported as manageable in most states, efficiency improvements may not be as much of a priority as power procurement optimisation and cost-reflective tariffs.

- Inflation-linked tariffs combined with ToD pricing and regular fuel surcharge adjustments can significantly improve DISCOM finances. Had inflation-linked increases been implemented during FY16–FY23, the accumulated revenue gap would have decreased by ₹4.41 lakh crore, translating to an annual additional revenue recovery of ₹60,000 crore, eliminating ₹1.6 lakh crore in interest costs.

Recommendations:

- Takeover of liabilities can be structured either as a one-time exercise or in tranches, subject to clear conditionalities—particularly adopting inflation-linked tariffs, improved power procurement practices and rapid deployment of agricultural solarisation.
- Agricultural solarisation should be prioritised through centralised or MW-scale feeder-level decentralised models within a 5–7 year time frame. To support this, states should be incentivised to (1) align agricultural supply with solar hours and (2) ensure feeder segregation, both of which are prerequisites for agricultural solarisation. Because savings are higher with faster adoption, rapid deployment must be encouraged by continuing the current central financial assistance of ₹1.05 crore/ MW of solar capacity contracted for feeder-level agricultural solar projects under PM-KUSUM. In addition, central sector grants for feeder segregation, capital works are also critical and should be continued.
- With significant AT&C loss reduction already reported by many DISCOMs, further improvements will require substantial investment and sustained state government support. A more effective strategy would be to focus on revising tariffs in a timely manner and rationalising power procurement costs (for example, through agricultural solarisation), which could deliver a stronger financial impact.
- Given the improvements in timely revenue recovery and interest cost savings, inflation-linked tariffs should be adopted in states where (1) regulatory assets or cumulative revenue gaps exceed 3% of revenue or (2) working capital borrowings account for more than 50% of total borrowings.
- Inflation-linked tariffs should be complemented with other pricing measures such as regular levy of fuel surcharge and renewable energy supply aligned time of day tariffs.

6 Privatisation and Private Participation in Electricity Distribution

Privatisation of distribution companies has been considered as an option to improve their operational efficiency, especially by reducing their AT&C losses. However, private participation in the distribution business has been limited in scope so far. Currently, 49 privately-owned DISCOMs operate in India accounting for approximately 10% of total electricity sales (CEA, 2024a). Of these, 34 are small DISCOMs limited to supplying Special Economic Zones (SEZs) and industrial areas, 11 are large city-based DISCOMs[66], and only 4 private utilities cater to both rural and urban areas—all located in Odisha.

Among these 49 licensees, only 10 resulted from privatisation of state-owned DISCOMs. Seven emerged from privatisation exercises in Delhi and Odisha and one from the development in Noida during the 1990s.Two are more recent with the privatisation initiatives in Dadra and Nagar Haveli Daman and Diu, as well as Chandigarh between 2021 and 2023. As part of the same initiative of the union government to privatise distribution licensees in union territories, efforts are underway to privatise utilities in Puducherry and Andaman and Nicobar Islands. Recent developments indicate renewed interest in privatisation, especially with the re-privatisation exercise in Odisha in 2020 and proposals for privatising two DISCOMs in Uttar Pradesh.

The privatisation experiences in Delhi and Odisha are sufficiently extensive and developed to offer meaningful lessons for policy consideration. When evaluating privatisation options in other states, the Odisha experience may be particularly relevant as it remains the only state in India where private utilities serve significant rural populations alongside urban areas.

6.1 The privatisation experience in Delhi

The privatisation of Delhi Vidyut Board (DVB) was initiated in 2002 to address high AT&C losses of 55% and substantial outstanding liabilities. The reform established three geographically distinct licensees through competitive bidding based primarily on AT&C loss reduction: BSES Yamuna Power Limited (BYPL), BSES Rajdhani Power Limited (BRPL) owned by the Reliance Group, and Tata Power Delhi Distribution Limited (TPDDL). The Delhi Government retained 49% equity stakes in all entities. The privatisation framework required the Delhi Government to assume DVB's outstanding liabilities of ₹19,000 crore and provide transitional support of ₹3,540 crore over five years (PEG, 2006; Hasan & Gaba, 2009).A significant portion of the liability takeover was managed as part of the 2001 SEB Bailout Scheme referred to in Section 3.1.2.

Post-privatisation performance demonstrated significant operational improvements. AT&C losses declined from 55% in FY02 to 30% in FY07, with two of the three DISCOMs currently reporting losses at 6.65% (CRISIL , 2010; PEG, 2006; PFC, 2025). By way of comparison, in Mumbai (BSES), AT&C losses declined from 13% in FY02 to 7.05% in FY07. Marked improvement in supply and service quality was also observed. In fact, distribution transformer (DT) Failure rate, a robust indicator of supply and service quality, saw a marked reduction from 18% in 2002 to 0.1% - 0.9% by FY24 (Hasan & Gaba, 2009; REC, 2025). For context, the average DT failure rate across DISCOMs in India is about 6.5% in FY24 (REC, 2025).

[66] This includes two DISCOMs in Mumbai, three in Delhi, and one private DISCOM each in Kolkata, Surat, Ahmedabad, Noida, Chandigarh, and Daman and Diu.

In FY24, sales to residential consumers accounted for 50-64% of the total sales, with approximately 50% of power sourced from central sector generating companies. The DISCOMs depend on state government revenue subsidies to meet at least 10% of their expenses. The Delhi government provides free power to domestic consumers using less than 200 units and 50% subsidies for those using 201-400 units.

Privatisation has not eliminated fundamental financial challenges. Payments to generators does not take place on time with average payables close to nine months (PFC, 2025). Over the years, key issues include inefficient procurement practices with heavy dependence on high-cost short-term power purchases, substantial litigation arising from regulatory commission disallowances of capital expenditure and power procurement decisions and prolonged periods without tariff revisions (Chitnis, DMonty Nair, & Singh, 2025). Between FY05 and FY25, tariffs increased in only 7 of the 21 years and for 7 years, no tariff order was issued[67]. In the absence of cost-reflective tariffs, the regulatory assets (deferred revenue recovery from future tariffs) along with carrying cost was about ₹28,700 crore by FY23. This figure is as high as the annual expenses of the DISCOMs in Delhi (PFC, 2025).

6.2 The privatisation experience in Odisha

Following the unbundling of the State Electricity Board in 1997, Odisha's four newly created DISCOMs were offered for private participation in 1998. BSES Limited (subsequently part of the Reliance Group) acquired three DISCOMs, while AES Corporation led a consortium that acquired CESCO. The initial privatisation proved unsustainable. Within four years, AES Corporation's licence was revoked due to mounting dues to state-owned entities and operational disengagement. CESCO, renamed CESU, reverted to state control, with the government subsequently appointing franchisees[68] across 14 of 20 sub-divisions for revenue collection and network maintenance.

The Reliance-operated DISCOMs fared little better. After a decade characterised by persistent dues to generators, stagnant AT&C losses, minimal rural network investment, inadequate capital expenditure, and repeated regulatory non-compliance, the State Electricity Regulatory Commission revoked their licences in 2015—a decision upheld by APTEL and Supreme Court in 2017 (SCI, 2017; APTEL, 2017; OERC, 2015).

Between 2020 and 2023, through competitive bidding, 51% stakes in all four DISCOMs were awarded to Tata Power under a restructured model. It is interesting to note that Tata Power was the sole bidder because no other bidder qualified in the technical rounds (Bhaskar, 2020; PowerLine, 2020). Critically, similar to the previous privatisation exercise, GRIDCO, the state-owned utility, retained all power procurement responsibilities and long-term purchase agreements. DISCOMs procure power from GRIDCO at regulated bulk supply tariffs, limiting their operational scope to distribution network investment, management, billing, and revenue collection—functions representing merely 27% of the total sectoral expenses.

Under the bidding framework, Tata Power committed to ₹5,640 crore in capital investment (including ₹863 crore equity), AT&C loss reduction of 8-9 percentage points and arrear recovery of ₹1,000 crore over a five year period, with specified penalties for underperformance.

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[67] Based on authors' analysis of tariff orders issued by DERC between FY05 and FY25.

[68] The companies appointed were M/s Enzen Global Solutions Pvt. Ltd., Feedback Energy Distribution Company Ltd., and Riverside Utilities Pvt. Ltd./Seaside Utilities Pvt. Ltd.

Within their defined scope, the privatised DISCOMs in Odisha have delivered measurable improvements. AT&C losses have declined primarily through enhanced collection efficiency and arrear recovery exceeding ₹1,300 crore[69]—surpassing the initial commitments. Receivables (days) improved from 44 days (FY21) to 31 days (FY24) (PFC, 2025). Capital expenditure performance shows ₹3,797 crore capitalised against ₹4,342 crore committed between FY21-24. In addition, distribution transformer failure rates declined from 4.23% to 3.16% over the same period.

The model's apparent and initial success rests substantially on government de-risking mechanisms (Chitnis & Singh , 2025). The state took over 100% of the legacy liabilities during transition, effectively providing DISCOMs with clean balance sheets. While revenue subsidies are not provided by the state government, the state government has given the DISCOMs capital investment grants. Over the years, DISCOMs have received a total of ₹20,031 crore in capital grants from both central and state governments[70].

Crucially, as mentioned earlier, the state retained responsibility for power procurement through GRIDCO which undertakes the complex task of managing long-term power purchase agreements. The DISCOMs operate without revenue gaps but this stability is achieved at the cost of financial stress to GRIDCO. The bulk supply price fixed by the regulator is not cost-reflective, creating revenue gaps for GRIDCO. This gap was as high as 13% of the revenue requirement in FY23 and 7% in FY24. As per the regulatory commission, the deferred costs are not recovered from consumers but are to be financed through trade of surplus power or state government takeover of losses.

In addition, as on 30th September 2024, GRIDCO had not been paid ₹6,129 crore owed to it by the erstwhile DISCOMs (OERC, 2025). If the outstanding liabilities of the DISCOM were taken over by the state government, then GRIDCO should ideally have been paid. These dues are close in magnitude to the bulk of the liabilities to be taken over by the state government during the appointment of new licensees.

Thus, the state entity continues to face the same financial stress that privatisation was meant to address. Delayed payments, political interference in commercial decisions, and accumulating debt are still part of the Odisha power sector reality.

6.3 Lessons from Delhi and Odisha privatisation experiences

From the Delhi and Odisha privatisation experiences, the following lessons emerge for policy consideration:

Operational improvements are achievable with structured frameworks—Both the Delhi and Odisha experiences demonstrate that private DISCOMs can deliver measurable improvements in supply quality, service delivery and AT&C loss reduction. Enhanced metering, billing systems, revenue collection—including recovery of past receivables—and consistent capital investments are evident in both cases. However, for these outcomes to be realised, clear monitoring frameworks, defined performance trajectories and specified incentives need to be

[69] Based on data submitted by DISCOMs as part of various regulatory proceedings for tariff and true-up.
[70] This includes ₹ 400 crore from the 13th Finance Commission

established during the selection process. Else, the lack of interest as evinced in the first round of privatisation in Odisha is also a possibility.

Substantial state support remains a prerequisite—Private participation in Delhi and Odisha was possible due to extensive government de-risking. The state governments assumed all the legacy liabilities and wrote off significant pending receivables. The Delhi government provided additional transition finance over three years, while the Odisha government supported early network investments through grants and ensured competitive power supply costs via GRIDCO's bulk tariffs. This level of fiscal commitment may not be replicable across states.

Limitations of the cost-plus regulatory framework persist—The private DISCOMs' tariff determination and performance evaluation were under the cost-plus tariff framework. The transfer from public to private monopoly does not enable competitive price discovery. Like all other DISCOMs in India, these private DISCOMs were guaranteed 16% returns on equity, providing limited efficiency improvement incentives. Moreover, regulatory uncertainties that affect state-owned DISCOMs—including delayed regulatory decisions, disputes, litigation and accumulating interest costs—continue to affect private operators.

Political economy constraints remain—Despite private participation, the reluctance of state governments to approve cost-reflective tariffs has led to an increase in liabilities and deferred cost recovery in both cases. Delhi's regulatory asset build-up and substantial revenue subsidies, together with below-cost bulk supply tariffs of Odisha's state-owned GRIDCO and mounting liabilities in Odisha, demonstrate continued political control over pricing that prevent DISCOMs from operating on commercial principles.

Limited scalability due to unique preconditions—The implementation of both models benefitted from the unique contexts in Delhi and Odisha, which may not exist in other states. Delhi's predominantly urban geography, dense networks and residential-commercial consumer base facilitated the model's implementation. Odisha's large industrial consumer segment with demonstrated timely payments and GRIDCO's existing low-cost contracted capacity helped maintain competitive tariffs. These preconditions are not universally available across Indian states.

Thus, privatisation can improve operational efficiency and may be relevant in DISCOMs with unmanageably high AT&C losses. However, it may not lead to major benefits in states such as Andhra Pradesh, Telangana and Tamil Nadu, where AT&C losses are low and supply and service quality is relatively good. Privatisation models can neither address nor resolve the fundamental viability of the sector without tackling the challenges of cost-reflective pricing, regulatory certainty and performance accountability. These are challenging to achieve in cost-plus tariff determination regimes. Success requires substantial fiscal commitments and a potential revenue-generating base for private players. In this context, policymakers should evaluate whether privatisation in areas with relatively low AT&C losses and good supply quality addresses the underlying sector problems or merely redistributes financial stress within the system.

6.4 Experience with input-based franchisees across nine states

Another model of private participation aimed at AT&C loss reduction is to appoint franchisees to manage revenue collection, billing, metering and network management in an area within the DISCOMs' area of supply. The DISCOM supplies power to the franchisee at a pre-stipulated bulk supply rate (called the input rate), which is indexed to the average tariff. The franchisee in turn collects revenue from the DISCOM consumers in the demarcated area at regulated tariffs.

Improved collection and rapid AT&C loss reduction should thus translate to significant gains for the franchisee while ensuring fixed recovery for the DISCOM. The first franchisee was appointed in Bhiwandi in FY07 by MSEDCL, the state-owned DISCOM in Maharashtra, over a ten-year period. The franchisee was awarded to Torrent Power Limited (TPL) through a competitive bidding process. TPL was also allowed to undertake capital investments as long as the assets were handed over to the DISCOM with mutually agreed compensation arrangements. The losses decreased dramatically within a short period from 63% in FY07 to 19% by FY09. Metering and supply quality also improved and the period also saw rapid transformer capacity addition (PEG, 2009; Chitnis A. , 2024).

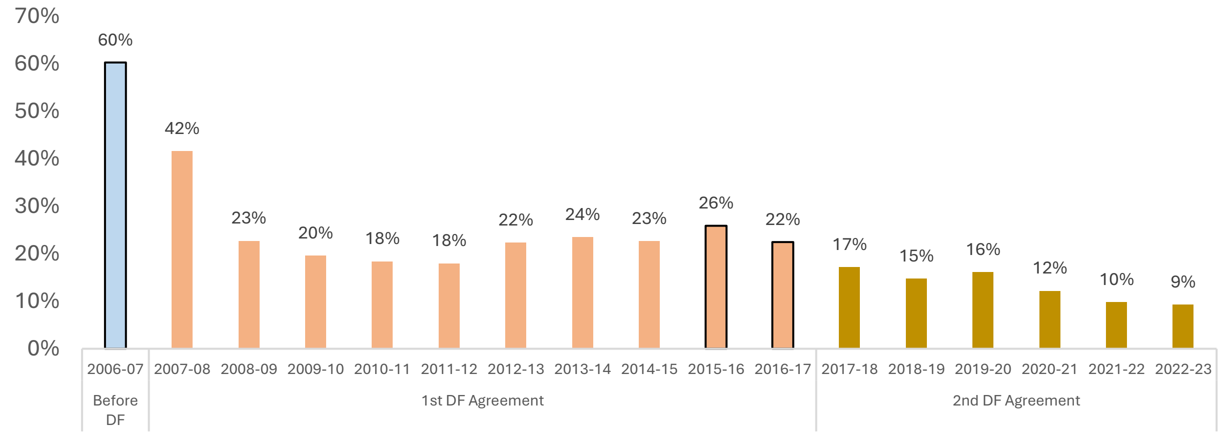
However, this early success has not been consistently replicated across other implementations. Of the 28 distribution franchisees (DFs) appointed between 2008 and 2025 across nine states in India, only 11 remain operational today. Four contracts were discontinued with the appointment of private licensees in Odisha. Among the non-operational franchisees, 52% were terminated due to non-payment of dues or poor performance, and 23% were unable to take over operations in the area due to operational challenges and on-the-ground opposition. More details in Annexure 11.

There were also issues related to bidding process in Agra, Kanpur, Bhiwandi, and issues related to area selection in Kota and Bharatpur (CAG, 2013; CAG, 2022; PEG, 2009). In Agra, the selection process itself made it challenging for the DISCOM to realise benefits from the arrangement. The baseline T&D losses in FY09 considered for target AT&C loss reduction were revised from 28.22% in the RfP to 44.85% in the revised agreement—a significant 16.63 percentage point increase after selection. A similar increase was also made in collection efficiency as well as the average tariff considered. As observed by the CAG, no explanations were provided for these changes and because of this, the DISCOMs would incur a revenue loss of about ₹3,800 crore during the course of the agreement (CAG, 2013). Under these terms, the DISCOM would not benefit from the arrangement. By 2016, Torrent Power, the appointed franchisee, reported T&D losses of 32%. This was higher than the original RfP baseline and lower than the revised agreement baseline reported for FY09 (UPERC, 2017).Third party performance audits of the franchisee performance are not available in the public domain to verify future loss reduction claims.

In general, the absence of third-party audits of franchisees in the public domain makes it challenging to evaluate their performance. However, available performance information—some from audit reports—was compiled for 5 of 11 existing franchisees in two states (Maharashtra and Rajasthan) as part of this study to provide a broad overview.

In Bhiwandi, Maharashtra, the dramatic reduction in AT&C losses continued beyond FY09, falling to 22% by FY17— when the agreement was renewed for an additional 10-year period (see Figure 6). MSEDCL reported sustained AT&C loss reduction during the second agreement period, from 17% in FY18 to 9% in FY24.

Figure 6: AT&C losses (%) in Bhiwandi under two DF agreement periods



Source: Compiled from MSEDCL regulatory filings as part of the tariff process, franchisee audit reports

Between FY07 and FY17, significant improvements in metering and supply quality, along with rapid transformer capacity additions, were reported to the DISCOMs and verified by third-party auditors. According to MSEDCL reports, the DT failure rate fell from 34% in FY07 to 0.87% by FY17. Between FY12 and FY17, under the franchisee arrangement, TPL earned ₹4,019 crore (38% of revenue billed to consumers), while MSEDCL retained the remainder as fixed earnings at the input rate.

In FY20, MSEDCL appointed TPL as franchisee for Shil, Mumbra and Kalwa (SMK), and CESC Ltd for Malegaon. In both cases, MSEDCL reported reduction in AT&C losses as well as DT failure rates over a three-year period in their annual audited financial statements/reports, as shown in Table 30.

Table 30: AT&C losses and DT failure rates in SMK and Malegaon

AT&C Loss (%)	**Before Handover**	**After Handover**		
	2019-20	2020-21	2021-22	2022-22
Shil, Mumbra & Kalwa	52.01%	52.6%	38.7%	32.8%
Malegaon	51.16%	55.8%	46.1%	38.8%
Distribution Transformer Failure Rate (%)	**Before Handover**	**After Handover**		
	2019-20	2020-21	2021-22	2022-22
Shil, Mumbra & Kalwa	12%	8%	4%	4%
Malegaon	22%	22%	21%	17%

Source: MSEDCL Annual Financial Audit Statements, various years

In Rajasthan, JdVVNL, a state-owned DISCOM appointed CESC in 2017 to manage operations in Bikaner, and in the same year, AVVNL appointed Tata Power to manage operations in Ajmer city. In Bikaner, audit reports submitted to the regulatory commission show an improvement in collection efficiency but mixed trends for distribution loss reduction, as is clear from Table 31. Perhaps more recent data will clarify the trend. In the case of Ajmer, the collection efficiency is close to or exceeds 100%, and distribution losses are also low. It is therefore unclear what the franchisee's objective is. Low losses could also mean low revenue earning potential for the franchisee, as shown in Table 31.

Table 31: Performance status for Bikaner and Ajmer City franchisees

Performance Parameters for Bikaner Franchisee	FY18	FY19	FY20	FY21	FY22
Distribution Loss (%)	11.40%	17.13%	13.84%	Data Not Available	
Collection Efficiency (%)	79.54%	95.46%	92.57%		
AT&C Loss (%)	29.50%	20.90%	20.20%		
Revenue Collected Paid to DISCOMs (₹ Cr)	372	468	479		
Share of revenue collected retained by DF	-4%	6%	10%		
Performance Parameters for Ajmer City Franchisee	**FY18**	**FY19**	**FY20**	**FY21**	**FY22**
Distribution Loss (%)	8.02%	11.18%	9.78%	10.50%	10.47%
Collection Efficiency (%)	92.10%	103.40%	94.97%	106.15%	101.43%
AT&C Loss (%)	15.30%	8.20%	14.30%	5%	9.20%
Revenue Collected Paid to DISCOMs (₹ Cr)	268	417	414	459	452
Share of revenue collected retained by DF	16%	17%	11%	18%	11%

Source: Data compiled from franchisee audit reports submitted to the Rajasthan Commission

Input-based franchisees present a viable mechanism for addressing distribution areas with persistently high losses, because the model ensures guaranteed revenue recovery for DISCOMs while creating appropriate commercial incentives for franchisees to optimise operational efficiency. However, successful implementation requires transparent and competitive bidding processes, detailed base-line surveys and well-defined performance benchmarks for loss reduction, and effective regulatory oversight mechanisms to ensure adherence to contractual obligations and maintain service quality standards. Without these critical safeguards, DISCOMs face the additional financial risk of franchisee defaults and non-payment of dues, undermining the intended benefits of the arrangement.

6.5 Other potential models for private participation

DISCOM privatization and input-based franchisees were primarily focused on improving collection efficiency and reducing distribution losses, and were actively promoted over the past two decades when AT&C loss reduction was a major challenge across the sector. Although still important, as detailed in Section 5.4, many states have already reported substantial improvement in reducing AT&C losses, a trend expected to strengthen further with the rollout of smart metering. However, working capital borrowings are increasingly crowding out essential capital investments, and financial pressures have led to deferred operation and maintenance (O&M) activities. This highlights the need for private participation in building and maintaining networks to ensure reliable supply. In this context, the following two, yet untested models of private participation are possible:

6.5.1 Competitive bidding for sub-transmission assets

DISCOMs can invite investment in HT networks through competitive bidding to build, augment and maintain sub-transmission or distribution assets in a timely and efficient manner. The assets would continue to be owned and operated by the DISCOM, while the franchisee would receive fixed annuity payments for the duration of the contract, linked to network performance parameters.

6.5.2 O&M franchisees

DISCOMs can also appoint franchisees in select feeders or divisions to ensure timely and reliable O&M activities are undertaken. Unlike input-based franchisees, this model does not focus on revenue collection but can be structured on a revenue-sharing basis, tied to reliability and other performance targets.

Key takeaways

- Ten DISCOMs have been privatised in India (seven in Delhi and Odisha, one in Noida, and two recently in Dadra-Nagar Haveli Daman-Diu, and Chandigarh).
- Experiences from Delhi and Odisha show that privatisation can improve service quality and reduce AT&C losses but requires substantial state support, including liability takeover, transition financing, and subsidies or capital grants. Political economy constraints also persist for the private utilities through delayed tariff adjustments and regulatory uncertainty. Further, the cost-plus structures limit efficiency incentives, and the necessary conditions for replication (high AT&C losses, poor service quality and a significant paying consumer base) may not exist in all states.
- Input-based franchisees appointed by DISCOMs provide an alternative model for private participation, targeting very high-loss pockets while ensuring fixed revenues for DISCOMs. The model saw early success in Bhiwandi and generated significant interest. However, only 11 of 28 franchisees appointed across nine states remain operational. Failures were largely due to non-payment of dues or poor performance (52%), operational challenges, or on-the-ground opposition (23%). Success depends on transparent competitive bidding, comprehensive baseline surveys, clear performance benchmarks, and robust regulatory oversight.
- It is crucial that states adopt private participation models through competitive bidding which are appropriate for the state context.
  - **Input-based franchisee:** Are best suited for high-loss pockets where AT&C losses are more than double the national average (32%). Agreements should specify loss-reduction trajectories, transparent monitoring, arrear recovery, and capital investment. They should also include significant penalties for delay in payment of dues and provide renewal options based on performance.
  - **Privatisation of the entire DISCOM:** Should be considered only in states with persistent AT&C losses, poor network management, and unsuccessful franchisee experience. Successful privatizations underline the importance of substantial state support: —liability takeover, transition finance and in-kind support (capex, power procurement). Pre-privatisation measures are also crucial: maintaining an asset registry, consumer indexing, streamlining billing and revenue collection, and establishing baseline AT&C losses.
- In addition, two as-yet untested models for private participation can be experimented with, primarily to increase private investments in distribution and reliability improvement:
  - **Competitive bidding for sub-transmission assets:** This model of private participation aims to improve and augment sub-transmission lines and assets in a timely and cost-effective manner through competitive bidding.
  - **O&M franchisees:** Franchisees can be appointed by the DISCOM for O&M of distribution networks in select feeders or divisions. This is different from input based franchisees, which are focused on improving revenue collection. This can be structured using a revenue-sharing of fixed annuity model tied to reliability and other performance targets.

Recommendations:

— Input-based franchisees should be appointed only in areas where the baseline measured loss is consistently higher than 32% (double the national average) for at least a five-year period. Franchisees should be appointed through a transparent, competitive bidding process with the agreement incorporating clear loss reduction targets, strict monitoring, arrear recovery mechanisms, capital investment requirements and penalties for non-payment of dues.

— Privatisation of an entire DISCOM would require substantial state government commitment and is a long-term decision. It should only be considered when the losses of the entire DISCOM remain persistently high, network management is weak, and franchisee models have failed. Further preparatory measures such as asset mapping, consumer indexing, streamlining billing and establishing credible loss baselines should be completed before hand.

— Because AT&C losses have reduced significantly, it is important to explore models for private participation which can improve network investment and reliability. In this context, state governments and DISCOMs can test new frameworks to attract investment and strengthen reliability including competitive bidding for sub-transmission and distribution assets and O&M franchisees for specific feeders or divisions.

7 Emerging trends, challenges and opportunities which affect DISCOM finances

In previous chapters, the key aspects of DISCOMs' financial challenges, the reasons behind their mounting losses and liabilities, and strategies to address these issues were discussed. However, any comprehensive strategy to achieve DISCOM financial turnaround must also consider six key emerging trends from the past five to seven years that are fundamentally disrupting and reshaping future DISCOM operations. These trends, listed below, are examined in this chapter:

— **State government subsidies are increasingly replacing cross-subsidies and have become the dominant source of tariff support for DISCOMs**. This has implications not only for state government finances but also for the DISCOM business model, as the financial impact of C&I consumers reducing their dependence on DISCOMs for supply might be manageable with the reducing cross-subsidy contribution.

— **Rapid scaling of agricultural solarization has been demonstrated as feasible and is already being implemented across multiple states.** While the potential savings from agricultural solarization have been detailed in Section 5.3, the adoption of these measures by DISCOMs to solarize the majority of their agricultural sales demonstrates the rapid scalability of this approach. Future costs, power procurement requirements, state government subsidy requirements, and cross-subsidy structures are significantly impacted by such rapid deployment.

— **Sharp decline in storage costs** is enabling renewable energy integration by DISCOMs and allowing consumers to exercise greater choice, while reducing their dependence on DISCOMs for power supply. The modular nature and two-year commissioning period of some storage technologies enables rapid scaling. This techno-economic shift opens up avenues for new business models and market innovation to meet reliability requirements of consumers.

— **Growing capacity and appetite for renewable energy investment has been demonstrated by C&I consumers**. This is fueled by the competitively low prices for renewable energy supply, much lower than DISCOM tariffs, combined with enabling legal frameworks and the commitments made by enterprises to be globally competitive.

— **Despite this shift, C&I consumers continue to depend on DISCOMs for reliability services while such services continue to be underpriced by DISCOMs.** This is particularly because cost compensation frameworks focused on loss of cross subsidy revenue and cost impact of underutilization of contracted coal capacity due to open access, mechanisms which are slowly losing relevance. Further, reliability services especially for peak-period supply provision, renewable energy banking and standby services are not priced at the cost of the service provided. The pricing is bundled along with other charges or is underpriced, leading to lack of clear future-ready pricing frameworks and revenue loss.

— **While several efforts to deepen electricity markets are underway, liquidity constraints persist with DISCOMs positioned as the predominant supplier.** While there is a significant push for reforms in electricity markets, especially related to power exchange operations, such markets are highly dependent on DISCOMs' short-term power procurement strategies without much participation from consumers directly. However, with increased participation of consumers, significant innovation in contracts, price discovery would be possible. With such participation, markets could evolve to cater to contracts for various durations and services rather than being restricted only to marginal, short-term procurement.

7.1 State subsidies replace cross-subsidy as the primary revenue support for DISCOMs

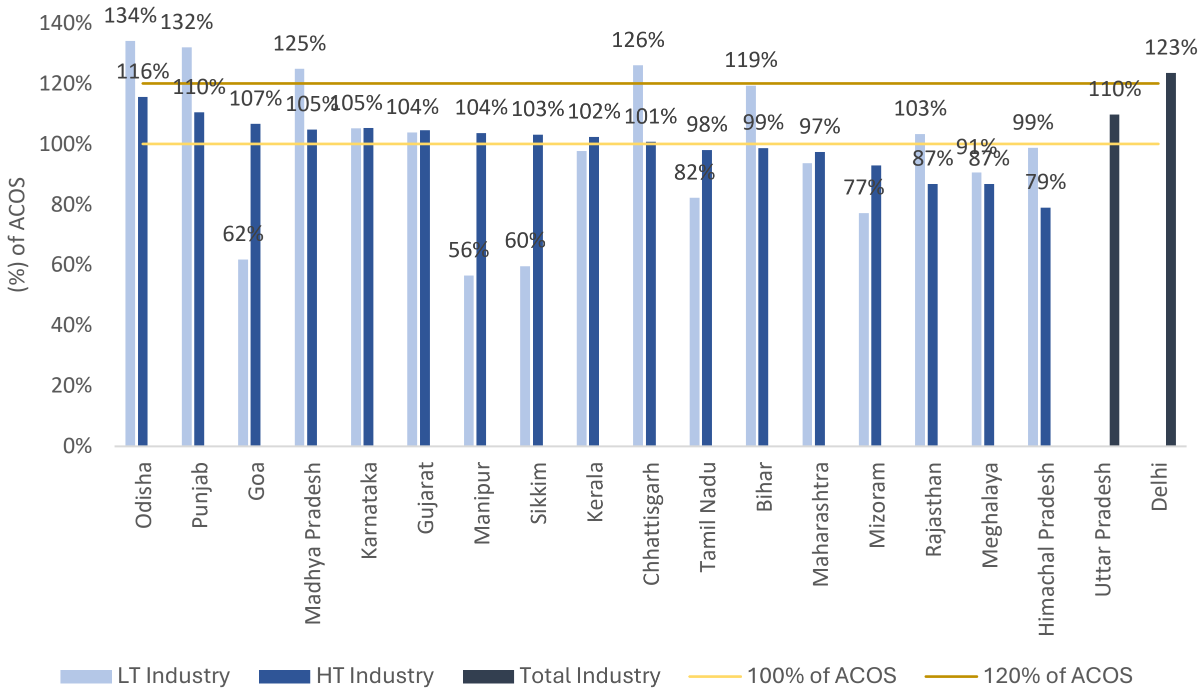
Cross-subsidy has long been considered a defining characteristic of the tariff structure in India's power sector. Under this mechanism, C&I consumers have historically paid tariffs above the average cost of supply (ACOS) to offset the below-cost tariffs charged to residential and agricultural consumers (MoP, 1980). This arrangement enabled DISCOMs to maintain financial viability while ensuring that priority consumer segments could afford electricity.

Traditionally, cross-subsidy provided/required is expressed as the percentage by which the average tariff exceeds/falls short of the ACOS. The National Tariff Policy mandates a gradual reduction in cross-subsidy levels, stipulating that consumer tariffs should range between 80% to 120% of the average cost of supply (MoP, 2006; MoP, 2016). Over the years, actual average tariffs have converged to this prescription. Multiple factors have accelerated this convergence: regulatory efforts to reduce cross-subsidy, concerns about industrial competitiveness, and the migration of high-paying consumers to alternative supply options through open access and investment in captive plants.

Consequently, industrial tariffs have aligned more closely with the actual ACOS in recent years (Figure 7). The analysis of the tariff design in 17 states reveals that HT industrial tariffs charged to consumers now fall below 120% of the actual ACOS in all the studied states. Remarkably, in 7 states, these tariffs are below 100% of the ACOS and in 7 other states, the tariffs range between 101% to 105% effectively eliminating their cross-subsidising role. Thus, it is only in Odisha, Punjab and Goa that regulated tariffs are more than 105% of ACOS. LT industrial consumers, who lack alternative supply options, face higher tariffs than their HT counterparts in eight states.

Commercial consumers exhibit a similar pattern, though with greater variation. Whereas HT commercial tariffs exceed 120% of the ACOS in nine states, they fall below the actual ACOS in six states and are approximately at ACOS in two states. LT commercial consumers face higher tariffs than their HT counterparts in three states. However, even if the percentage of per unit revenue is much higher than cost, given the relatively lower sales volume to commercial consumers, their contribution to overall cross-subsidy revenue remains limited. See Annexure 12 for more details.

Figure 7: Industrial average tariffs as a percentage of the average cost of supply in FY23



Note:

a. This analysis is based on the actual ACOS for the year and actual average tariffs based on net ARRs, actual category-wise sales and category-wise revenues actually billed. In that sense, the tariff depicted here in relation to the cost of supply will vary from data in centralised databases such as REC's report on Key Regulatory Parameters of Power Utilities and CEA's report on Tariff and Duty of Electricity Supply in India (REC, 2025; CEA, 2025b). This is because both of these reports capture tariffs and costs projected by the SERC and not the actual tariffs billed and costs incurred. Actuals provide a better understanding of cross-subsidy requirements than projections because there is significant variation not just in cost and revenue but also in sales.

b. Category-wise LT and HT distinction in sales and revenue was not clear with data reported in Uttar Pradesh and Delhi, which is why the data is reported for Total Industrial category.

Source: Analysis based on true-up orders/petitions, annual audited financial statements/reports of DISCOMs.

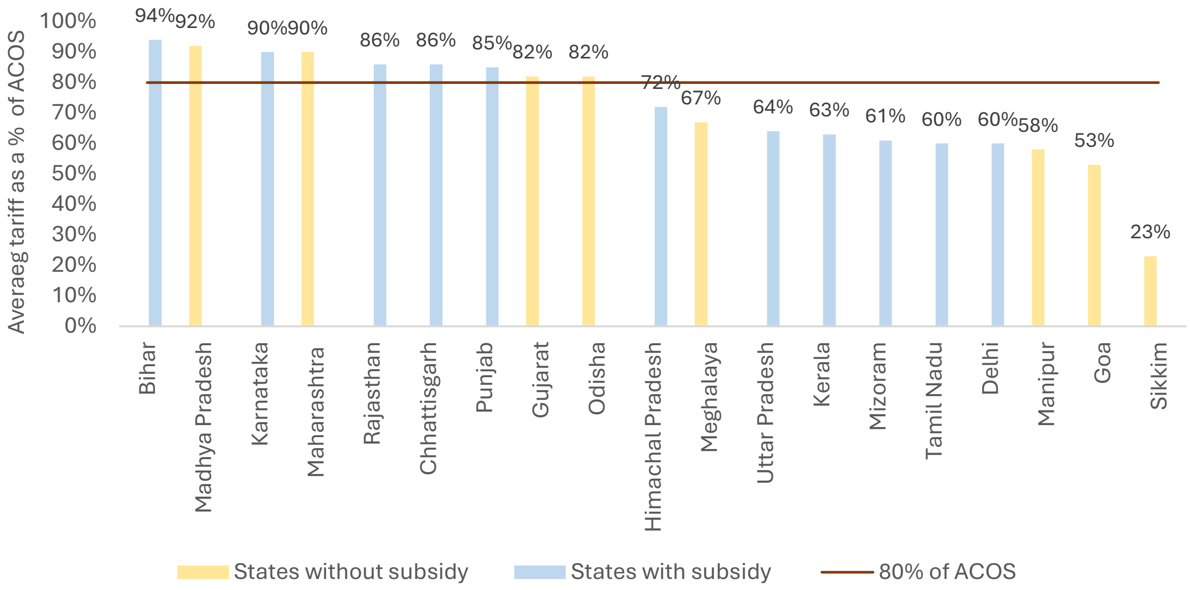
In conjunction with efforts to limit cross-subsidy contributions from C&I consumers, regulators have worked to reduce cross-subsidy requirements from agricultural and domestic consumers. Data on actual expenses, revenue billed and sales used to estimate status of cross-subsidy requirement shows the following:

— DISCOM in nine of the 19 states, which account for 41% of the total residential consumer sale in India have set domestic tariffs above 80% of the ACOS, with four of these states have tariffs exceeding 90% of ACOS. Notably, in five of these nine states, state governments continue to provide subsidies to domestic users (Figure 8).

— DISCOMs in five of 18 states have agricultural tariffs exceeding 80% of the ACOS, with two other states maintaining them at approximately 70% of the ACOS. In these seven states which accounts 40% of the national agricultural electricity consumption, agricultural consumers receive electricity subsidies, often resulting in heavily subsidised or free power. In four of these seven states, agriculture comprises more than 20% of total electricity sales, signifying significant contribution of revenue from agricultural electricity tariffs (Figure 9).

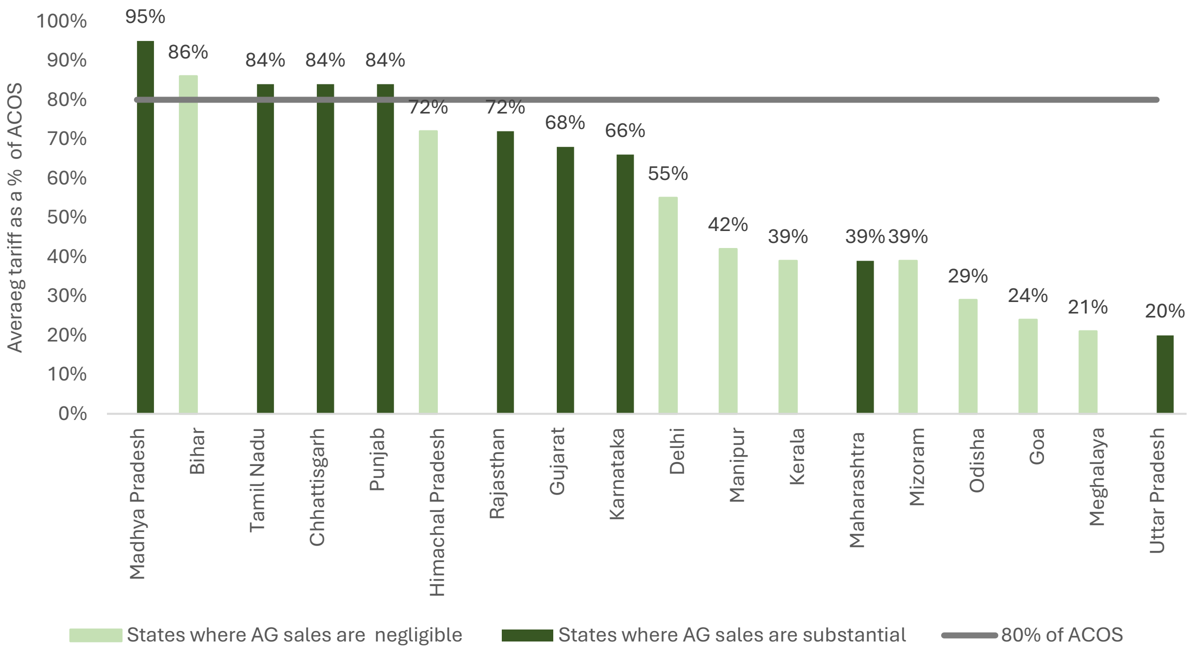
Despite regulatory tariff increases, agricultural and domestic consumers are not necessarily paying higher bills. Instead, the cross-subsidy support is being systematically replaced by direct state government subsidies.

Figure 8: Actual average tariff for LT Domestic consumers as % of the ACOS in FY23



Note: This analysis is based on the actual ACOS for the year and actual average tariffs based on net ARRs, actual category-wise sales and category-wise revenues actually billed.
Source: Analysis based on true-up orders/petitions, annual audited financial statements/reports of DISCOMs.

Figure 9: Actual average tariff for LT Agriculture (AG) as % of the actual ACOS in FY23



Note: This analysis is based on the actual ACOS for the year and actual average tariffs based on net ARRs, actual category-wise sales and category-wise revenues actually billed.
Source: Analysis based on true-up orders/petitions, annual audited financial statements/reports of DISCOMs.

To quantify this shift from cross-subsidy support to subsidies, the actual revenue contributions from cross-subsidies were calculated. The methodology involved the following elements:

— Extracting actual category-wise sales, tariffs and overall cost data from tariff petitions and orders

— Calculating category-wise revenue and costs based on actual average tariffs and actual sales
— Comparing revenue against costs to determine cross-subsidy contributions or requirements

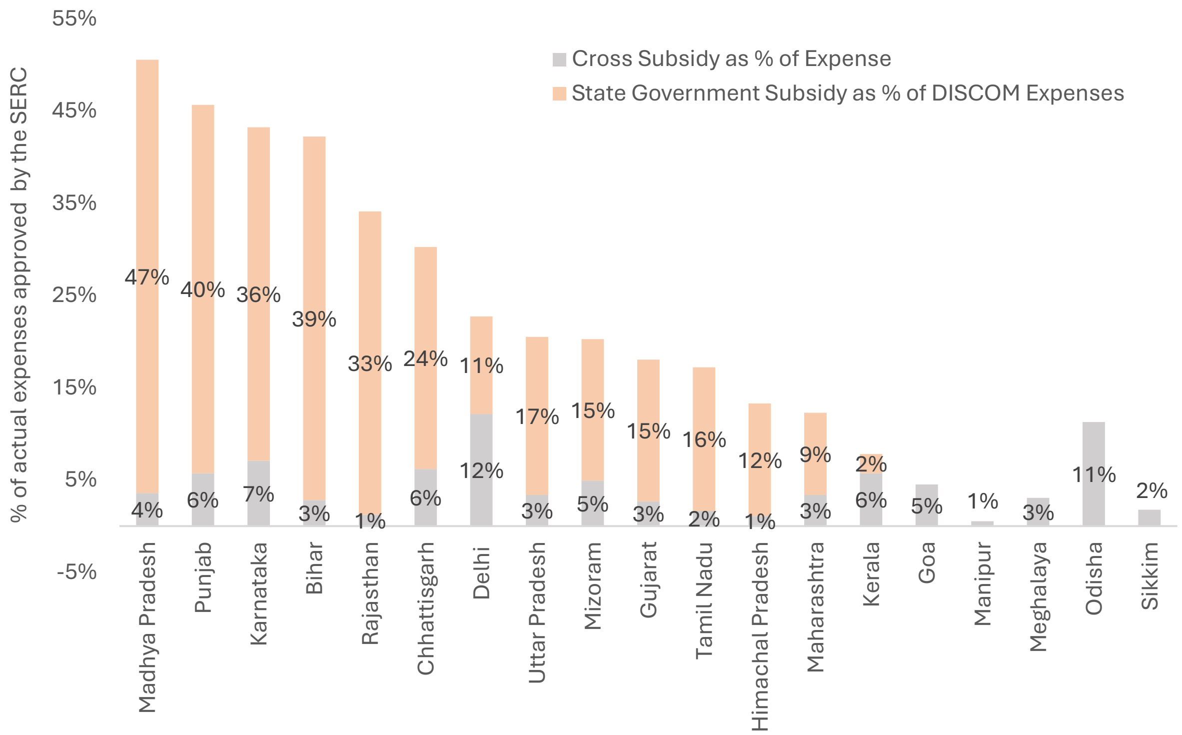
It must be noted that the cross subsidy estimated in this chapter is assuming an average uniform cost of supplying one unit of power to all consumers. However, cost of supply varies from consumer to consumer based on time-of-use and voltage-level of the consumer connection. Variation in cost of supply could not be captured due to data constraints. This data constraint persists despite repeated regulatory mandates requiring DISCOMs to furnish voltage-wise cost disaggregation.

However, it should be noted that regulatory commissions also consistently employ average cost of supply as the benchmark metric in their determination of revenue gaps, cross-subsidy quantum, and cross-subsidy surcharge computations within the tariff-setting framework, thereby establishing this as the accepted regulatory standard.

As the revenue used in this methodology is actuals rather than projections, the revenue used for the average tariff calculation also includes revenue from time of day tariffs and fuel surcharges levied over and above the approved tariffs, making it a more comprehensive account of average tariffs.

Figure 10 compares the revenue contribution of cross-subsidy and the state government subsidy billed as reported for FY23 with the revenue requirement (actual expenses passed through by regulators) of the state-owned DISCOMs for the year.

Figure 10: Cross subsidy and state government subsidy as % of expenses for FY23 (actuals)



Source: Based on revenue subsidy billed as reported for FY23 in (PFC, 2025) and actual sales, revenue and cost data captured from true-up orders and petitions of the DISCOM for FY23.

The analysis shows the following:

- **State government subsidies** constitute 24–47% of revenue requirements in six states and 9–16% in seven other states.
- **Cross-subsidy contributions** have decreased to less than 10% of revenue requirements in all states except Delhi and Odisha, with eleven states recording contributions below 5%.

This shift carries profound fiscal and political economy implications. The increased dependence on state government subsidies places substantial pressure on state government expenditures and raises questions about fiscal sustainability. Conversely, the reduced dependence on cross-subsidy revenue fundamentally alters the traditional dynamic where C&I consumers were crucial for the financial viability of DISCOMs.

Paradoxically, as explored in Section 7.5, these same C&I consumers may now benefit from various services, which are underpriced, where costs are socialised across all consumers, suggesting they too have become recipients of implicit cross-subsidies. This evolution challenges long-held assumptions about tariff design and consumer categorisation in India's power sector.

7.2 Rapid scaling of agricultural solarisation is possible and is already underway

As detailed in Section 5.3, substantial cost savings and reduction in state government subsidy are possible if daytime solar power for agriculture is implemented. Recognising this, several states have undertaken efforts to solarise agricultural connections at scale. Based on analysis of regulatory orders approving contracted capacity as well as tender announcements in states, the status till June 2025 across states has been compiled.

The state that recorded most progress is Maharashtra. Maharashtra has contracted 18,770 MW a total of solar capacity through decentralised options to meet agricultural demand (MERC, 2025). This capacity effectively covers 85% of the state's agricultural consumption—a significant achievement given that Maharashtra has the highest quantum of agricultural demand in India. Remarkably, 85% of this capacity was contracted within just nine months following the launch of *Mukha Mantri Saur Krushi Vahini Yojana* 2.0 (MSKVY 2.0). This accelerated deployment at scale under the scheme succeeded due to the state government's comprehensive framework addressing the inherent implementation challenges in the decentralised, feeder level aggregation approach (GoM, 2023):

- Incentive of ₹0.15–0.25 per unit for three years to reward early commissioning, supported by a ₹700 crore revolving fund to ensure timely payments to developers, derisking the business especially given small project sizes.
- Grants of up to ₹25 lakh per substation for DISCOM infrastructure augmentation to support decentralised generation.
- Identification of government land within 5–10 km radius of the dedicated agricultural feeder/substation. In addition, geo-tagged substation and land parcel details provided to developers. This helped with fast-tracking siting of projects and addressing land availability challenges.
- Establishment of a single-window portal for project clearances and real-time monitoring systems towards timely commissioning. In addition, advance/priority clearance and grid connectivity was also provided. This helped address implementation bottlenecks in a timely manner.

- With the small project size of 1 to 10 MW, a cluster-based/group based approach to bidding for 250 MW or higher was introduced to provide attract credible, established solar developers.
- Social development grants of ₹5 lakh per year for three years to Gram Panchayats

Because the tariffs discovered under competitive bidding range from ₹2.9/unit to ₹3.3/unit, the savings potential is significant. The Government of Maharashtra has estimated that deployment of such capacity would save the DISCOM ₹10,000 crore per year, and the state government would save ₹4,000 to ₹5,000 crore per annum in subsidies (GoM, 2024).

MSEDCL has also contracted storage capacity which is to be co-located with the solar capacity at the feeder level to improve reliability (MERC, 2025a). This will further reduce the dependence on the DISCOM to meet reliability requirements for these consumers.

In addition to this capacity, the Government of Maharashtra is also providing 90% capital grant for solar pump installation to consumers under the *Magel Tyala Saur Krushi Pump Yojana*. This will cover about 10% of pumpsets in the state. With solarisation of feeders and pumpsets, Maharashtra will be providing solar power to all its farmers by 2030.

The MSEDCL experience has demonstrated that rapid scaling of agricultural solarization through feeder-level deployment is not only feasible but can also create strategic opportunities for DISCOMs to restructure their operational responsibilities. With complete solarisation of agriculture, the Government of Maharashtra and MSEDCL are exploring the establishment of a dedicated entity to manage agricultural network operations and power supply—effectively allowing the DISCOM to carve-out this historically challenging segment and insulate it from their main operations. While this proposal remains in early stages with several aspects requiring further clarification, the Maharashtra experience offers a crucial insight: large-scale agricultural solarization enables DISCOMs to hive off supply obligations that have traditionally strained their financial resources and cross-subsidy mechanisms. This approach reduces the DISCOM's dependence on cross-subsidization from other consumer categories while allowing for dedicated, focused management of agricultural power supply challenges that have long affected the sector.

Significant progress has also been achieved in other states as well, especially under the KUSUM C scheme of the central government for feeder level solarisation detailed in Section 5.3:

- **Rajasthan** DISCOMs contracted 4,791 MW of capacity, with 96% capacity being contracted since May 2024. Further, the commission has also provided in-principal approval to contract an additional 6,000 MW with a ceiling tariff of ₹3.04/unit.
- In **Gujarat**, about 1,746 MW has been contracted under the feeder solarisation approach with multiple substation-wise tenders. The discovered tariffs range from ₹2.4/unit to ₹3/unit, which are among the lowest in the country. In addition to the decentralised approach, Gujarat is also attempting to ensure that solar power is provided through centralised procurement under the Kisan Suryoday Yojana. From FY21 to FY26, over ₹7,500 crore has been allocated to strengthen the distribution and transmission networks in order to enable daytime provision of electricity to farmers (GoG, 2020; GoG, 2021; GoG, 2022; GoG, 2023; GoG, 2024; GoG, 2025).
- **Andhra Pradesh** DISCOMs have entered into an agreement with SECI to contract 7,000 MW at the rate of ₹2.71 per unit, which covers 90% of sales by 2032. This centralised capacity is

dedicated to meeting the agricultural supply requirements in the state. The AP Rural Agriculture Power Supply Company, a public undertaking, will manage the contracts to ensure nine hours of daytime supply to farmers in the state. In addition to this capacity, the DISCOMs are committed to segregating and solarising about 1,000–1,200 feeders, which, together with the centralised projects, would cover almost all of the agricultural consumers in the state.

— **Madhya Pradesh** DISCOMs have contracted 97 MW under the solar feeder approach, with regulatory approval to contract 1,387 MW through competitive bidding. Under a new scheme, launched in June 2025, the *Surya Mitra Krishi Feeder Scheme*, the state has tendered 1,200 MW on similar lines to the Maharashtra scheme. Some unique aspects include incentives for reactive power compensation and flexibility in quoting conditional financial assistance claimed by developers.

— **Uttar Pradesh** DISCOMs contracted 34.8 MW by FY25. However, the state has issued a Letter of Award (LoA) for over a 1600 MW of capacity in FY24, with a target of contracting 2,000 MW by 2027 (UPNEDA, 2024).

— **Bihar** DISCOMs have similarly already contracted 255 MW, with plans of contracting 1,200 MW under their *Bihar Jal Jeevan Hariyali Yojana* scheme.

These developments are significant for two key reasons. First, rapid scaling is achievable, as demonstrated by Maharashtra's experience, and states are increasingly recognising the need for agricultural solarisation while innovating and cross-learning to accelerate deployment. Second, several states are making network investments to support scaling. which will require assistance to facilitate rapid deployment, cost realisation and subsidy savings.

7.3 Sharp decline in storage costs is enabling RE integration and consumer choice

Storage technologies (battery energy storage systems as well as pumped storage systems) can be game-changing for the sector, especially in terms of grid integration of variable renewable energy, improving supply reliability especially in peak periods and in case of network constraints. It also helps optimise investments in and utilisation of the sector infrastructure. The concern has always been the **cost and scalability** of these new technologies in the Indian context. However, recent developments show that both cost and scalability are no longer major concerns.

Between 2022 and 2025, the BESS (Battery Energy Storage Systems) market has seen a dramatic reduction in discovered prices. This is driven by global technology scaling and price reduction but also supported by innovations in tendering and contracting by DISCOMs.

In April 2022, the Kerala DISCOM was among the first utilities in the country to issue a BESS tender for a 20 MW/40 MWh system operating for two cycles per day. The winning bidder quoted a price of ₹11.25 lakhs/MW/month. This was soon followed by a SECI tender for 1000 MW/2000 MWh for which ₹10.83 lakhs/MW/month was the discovered price. The discovered prices demonstrated industry interest in these new technologies. However, the tenders were eventually cancelled, given the evolving technology space and rapid price reductions seen after these price discoveries, amongst other possible considerations.

The breakthrough in competitive pricing came with GUVNL's tender in November 2023. GUVNL successfully awarded a tender for 250 MW/500 MWh at ₹4.49 lakhs/MW/month, representing a 60% reduction from the Kerala price discovered 20 months earlier. The winning bid was structured for double-cycle per day operation over a 12-year contract duration. The tender specified an allowable battery degradation rate of 2.5% per annum and a round-trip efficiency of 85%. Based on these specifications and assuming a discount rate of 8%, the levelized cost of storage output translates to ₹4.35 per unit of storage output[71]. This price discovery was achieved without viability gap funding (VGF) support from central or state governments, indicative of true market competitiveness of the technology.

Such competitive price discovery was also not a one-off event. In March 2024, GUVNL's subsequent tender for 500 MW/1000 MWh discovered prices at ₹3.72 lakhs/MW/month, a 16% reduction within four months. By January 2025, price discovery for identical capacity reached ₹2.80 lakhs/MW/month, representing a 26% decrease from the March 2024 auction. The per-unit cost of storage output based on the January 2025 discovered price was ₹2.71/unit. Clearly, with the recently discovered prices detailed in Table 32, BESS is proving to be an extremely cost-competitive option for grid-scale applications.

The consistent price reductions are indicative of the maturity of the technology and the number of investors and market participants in scaling BESS. Achievement of sub-₹4/unit storage costs without subsidies positions BESS as a viable alternative to manage peaking power demand and provide reliability during non-solar hours. The fact that such cost reductions were possible without VGF also demonstrates that such cost competitiveness is sustainable.

Table 32:Details of stand-alone storage discovered prices

Date	Nov-23	Mar-24	Jan-25
Procuring DISCOM	Gujarat (GUVNL)		
Status	Contracted, Under Execution		Tender Awarded
Developers	Indigrid, Gensol	Gensol	Solar World, HG Infra
Viability Gap Funding	None	None	None
Storage capacity (MW/MWh)	250/500	500/1000	500/1000
Winning bid (₹lakh/ MW/ month)	4.49	3.72	2.8
Cycles per day as per contract/ tender	2	2	2
Per unit cost/ Levelized cost (₹/kWh)	4.35	3.6	2.71

Note: A battery degradation rate of 2.5% per annum, round-trip efficiency of 85 and discount rate of 8% is assumed to calculated the levelized cost.
Source: Tender documents, regulatory orders and (IESA, 2025)

Beyond cost competitiveness, there is also demonstrable evidence of scalability in recent years. Between April 2022 and July 2025, 7 projects with 251 MWh of BESS capacity have been commissioned across 5 states. Two of these are stand-alone and 5 are co-located with solar projects. In addition, about 1.2 GWh is expected to be operational in 2025. Further, about 9.2 GWh is already contracted with expectations to be online before 2030 (IESA, 2025).

Some storage projects are “co-located” with solar as several renewable energy tenders today are accompanied with a storage component where storage is used for managing peak demand or towards firm and dispatchable renewable energy (FDRE) or Round the Clock (RTC) power. The CEA’s advisory recommends that utilities include co-located storage—equivalent to 10% of solar capacity with a minimum duration of 2 hours—in future solar tenders to manage

[71] For an annual storage output of 351 MUs in Year 1 to 252 MUs in Year 12, the annual payment is about ₹135 crore, translating to a levelized cost of ₹. 4.35 per unit of storage output.

intermittency and provide peaking support (CEA, 2025a). Further, SERCs in 14 states have specified an energy storage obligation (ESO) requiring DISCOMs to procure a gradually increasing percentage of their total energy consumption via energy storage systems. ESOs mandate that 4% of DISCOMs consumption by FY30 is through utilisation of energy storage. Such mandates would also aid in scaling of storage and mainstreaming of the technology.

Prices discovered in Solar+BESS tenders have also reduced from ₹6.99 in 2018 per unit to ₹3.13/unit in 2025, where storage availability is for 4 hours (IESA, 2025).

This cost trajectory enables even more comprehensive solutions. Analysis indicates that with appropriate sizing—assuming BESS levelized cost of ₹3.5/unit, solar at ₹3/unit, 85% battery efficiency, 3% annual degradation, 8% discount rate, and 10% network losses—renewable energy with storage can meet 90% or more of the industrial consumer demand at less than ₹6/unit average cost[72] (Chojkiewicz, Abhyankar, & Phadke, 2025). This is comparable or lower than the energy charges paid by industrial consumers for DISCOM supply in 21 of 28 states in India (REC, 2025). With the modularity and scalability of BESS, adoption of storage by consumers in the future to reduce dependency on DISCOMs will only accelerate the migration.

7.4 The ability and appetite of C&I consumers to invest in RE is substantial and growing

India's drive toward internationalizing its enterprises has created growing demand from companies to source energy from emission-free sources such as renewables. This shift is driven by the need to comply with internal sustainability commitments and meet emerging carbon border trade requirements, such as the Carbon Border Adjustment Mechanism (CBAM). For India's small and medium industries, the economic savings from renewables and the flexibility to choose competitive suppliers—rather than rely on monopolistic distribution companies—has proven increasingly attractive.

This requirement, combined with enabling legal and regulatory provisions and the compelling techno-economics of renewables, has resulted in significant increases in non-DISCOM sales in India, which are expected to continue growing and affect DISCOMs' existing business model.

Since 2003, consumers have been legally empowered to procure power directly from generating companies and traders through open access provisions mandated in Section 42 of the Electricity Act, 2003. Operationalized across all Indian states since 2008, this framework enables consumers with demand greater than 1 MW to sign third-party contracts or invest in power plants to meet part or all of their supply requirements.

The regulatory landscape has recently expanded with the notification of Green Open Access Rules in 2022, under which 29 State Electricity Regulatory Commissions (SERCs) have established Green Open Access Regulations[73]. This creates an enabling framework for smaller consumers with demand as low as 100 kW to access open access and procure supply from multiple, primarily renewable energy sources. The framework now enables all high-tension (HT) consumers—typically 100 kW and above—representing approximately 35% of the country's electricity demand, to utilize open access provisions.

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[72] Based on prices discovered in recent tenders it is clear that storage is currently available at rates less than ₹ 3.5 per unit and assuming a consumer with flat load 24x7.

[73] Kerala is the only state that has yet not notified Green Open Access regulations.

Between 2003 and 2015, many large C&I consumers established their own coal power plants to reduce dependence on DISCOMs. However, adoption was limited due to substantial capital investment requirements and fuel price and volume risks.

Over the past decade, declining renewable energy costs have prompted a significant shift toward renewable capacity investments, supported by concessional policies offering rebates on charges for renewable energy use. This transition has been further accelerated the compelling techno-economics of solar[74] and by both implicit concessions (concessional treatment of banking and standby services) and explicit concessions (rebates on transmission, wheeling, cross-subsidy, and additional surcharge).

Time-series data compiled for six key states—Maharashtra, Tamil Nadu, Gujarat, Karnataka, Rajasthan, and Madhya Pradesh—collectively representing 55% of India's high-tension industrial sales, reveals significant non-DISCOM consumption patterns. Between 2016 and 2024, open access and captive consumption accounted for varying shares across states: 16-25% in Maharashtra and 14-33% in Rajasthan, while showing higher shares of 44-64% in Tamil Nadu and 31-44% in Karnataka. In Gujarat and Madhya Pradesh, where many industries traditionally rely on coal-based captive power, the shares varied from 31-51% and 30-60% respectively.

Within the non-DISCOM segment, captive consumption strongly dominates, accounting for 80-95% of non-DISCOM sales across most states. Most significantly, the captive power landscape has undergone a dramatic transformation toward renewables—a shift with major implications for reliance on grid/reliability services. Tamil Nadu leads with renewables comprising 82% of captive consumption, followed by Karnataka at 72%, while even Maharashtra, with its significant industrial base, shows 48% renewable captive consumption. This high renewable share in captive installations marks a fundamental departure from traditional coal-based captive power and creates new challenges for grid management due to the intermittent nature of renewable sources.

In addition to open access and captive, the number of grid-interactive rooftop solar systems being installed on consumer premises has also been increasing. Of the 123 GW of solar capacity installed in India by August 2025, 21 GW is from rooftop solar systems (MNRE, 2025a). Of this, only 5.9 GW of this capacity is due to installations under the *Surya Ghar Muft Bijli Yojana* scheme for residential consumers with demand less than 3 kW (MNRE, 2025b). Many C&I consumers have reduced their dependence on DISCOM supply by using rooftop systems as well. In many states, this is extended through a net metering framework.

Unlike coal-based captive power, renewable open access, captive and rooftop sources create substantial dependence on DISCOMs, particularly due to seasonal and daily variations in demand and supply. This dependency must be viewed against the backdrop of significant fluctuations in captive and open access shares of total commercial and industrial consumption. Between FY16 and FY25, open access and captive consumption exhibited

[74] A solar plant requires an investment of less than ₹3 crore/MW and can be set-up in a 2 year time period. The landed cost of solar generation with applicable losses would be around ₹ 4.5/unit. An industrial consumer typically pays about ₹ 6-7 per unit in energy charges. During solar hours, the consumer thus saves about ₹ 2-3 per unit which is substantial savings.

substantial year-on-year variations[75]. These variations clearly indicate the demand uncertainty faced by DISCOMs, as consumers switch opportunistically between non-DISCOM and DISCOM sources based on price arbitrage. This opportunistic switching complicates procurement planning for DISCOMs, affecting costs.

Despite the established framework, these challenges are perhaps why de facto administrative and procedural barriers exist for accessing non-DISCOM supply, along with unclear charge applicability and processes. This acts as a major barrier for consumers to exercise choice, which can be managed with cost-compensatory frameworks.

The extent of non-DISCOM consumption and the growing share of renewable energy in captive investments confirm the inevitability of migrating DISCOM sales. As discussed in Section 7.3, with solar and storage being techno-economically feasible and cheaper than DISCOMs' cost of supply, it is expected that more consumers will reduce their consumption from DISCOMs. Administrative and procedural barriers might slow down the pace of this migration, but this will come at the cost of industrial competitiveness in the country. Clearly, frameworks need to evolve where consumers are allowed to choose their source of power through market-based contracts while DISCOMs are also compensated for the services they provide at market rates.

7.5 DISCOM services to open access consumers are bundled and underpriced

From a techno-economic standpoint, the major distinction between open access and captive consumers lies in the applicability of open access charges. Open access consumers must pay:

- cross subsidy surcharge (CSS) to compensate for lost cross subsidy revenue with migration of C&I consumers
- additional surcharge (AS) to cover the fixed costs of contracted thermal capacity that become underutilised due to reduced demand from open access arrangements

However, as per the Electricity Act, 2003, captive consumers, which invest in their own generation sources are exempt from these charges.

This exemption of CSS and AS for captive consumers was relevant in 2003, given India's significant capacity shortages at the time. The exemption aimed to encourage investments in captive generation, primarily coal-based, and required substantial up-front investments of ₹250–1,000 crore. These projects also faced fuel availability risks and had lengthy gestation periods of five to seven years.

Two decades later, the landscape has transformed dramatically. Most states have contracted significant coal-based capacity. Renewables, particularly solar power, now offer cost-competitive pricing with much shorter gestation periods of around two years. Their modular nature enables flexible sizing and investment requirements, suggesting that the historical exemptions for captive consumers may no longer be necessary or justified.

With increased renewable energy reliance by consumers, DISCOMs have become essential providers of reliability services, which are critical given the variable and intermittent nature of renewables. One such service used by captive consumers in most states is renewable energy

[75] Year on year variation in non-DISCOM sales ranged from 9% to 168% in Madhya Pradesh, 2% to 69% in Gujarat, and 2% to 38%, 4% to 16%, 1% to 22%, and 4% to 21% in Maharashtra, Karnataka, Tamil Nadu, and Rajasthan respectively.

banking, where surplus power in excess of consumption generated during solar hours or wind seasons is injected into the grid for use by the DISCOM. The energy is offset by consumption from the DISCOM at a later time when renewable energy generation is not available. This off-set takes place on an energy accounting basis and is calculated for each month or billing cycle. The offset energy is referred to as ‘banked’ energy. In essence, consumers rely on banking services instead of investing in storage, expecting storage services to be provided by the DISCOM through banking arrangements.

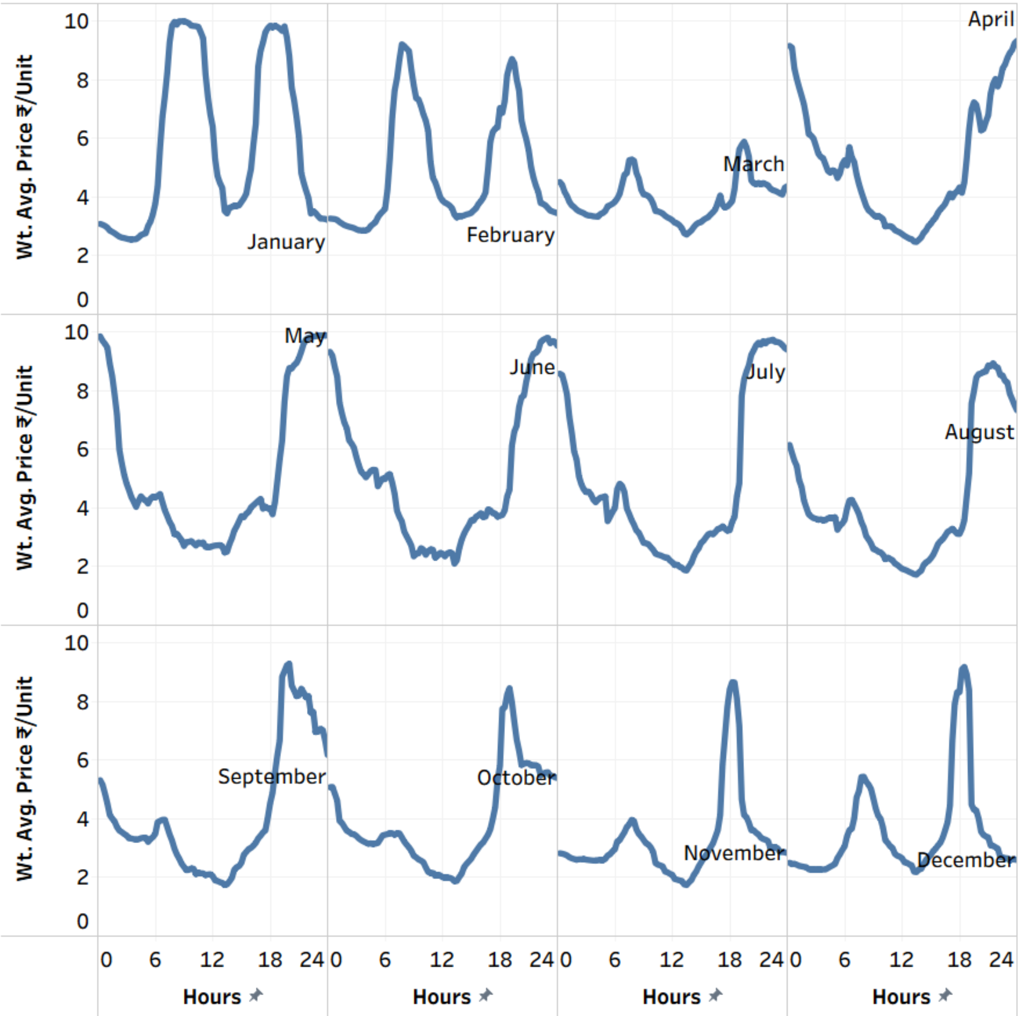
Another service is standby power, where in the case of generator failure, unavailability or unexpected increase in demand, consumers rely on the DISCOM to provide power at very short notice. At scale, this can significantly affect DISCOMs' power procurement costs.

Ideally, the DISCOM is perhaps best placed to provide such services at the least cost, given its key role as network operator, trader and bulk procurer of power. However, under the current regulatory regime and with the existing bundled tariffs, such services are not charged at cost-compensatory rates.

For the banking services provided, the cost should ideally reflect either the cost of storage or the difference in the marginal cost of power procured by the DISCOM between the period of injection and withdrawal. As discussed in the previous section, the cost of storage is around ₹3–3.5 per unit. Assuming that marginal power purchase is from market sources, the difference in market/power exchange discovered prices at the times of injection and withdrawal indicate the cost incurred by the DISCOM. As shown in Figure 11, there was significant variation in power exchange prices for FY24 across the day and seasonally.

— The prices during daytime/solar hours are markedly lower than morning and evening peak periods of 6 am to 10 am and 5 pm to 12 am, respectively.
— Further, nighttime (12 am to 6 am) prices vary significantly on a seasonal basis, with higher/peak pricing in summer months and from June to October.
— On average, in FY24, the nighttime price (12 am to 6 am) was 35% higher than the price for solar hours (10 am to 5 pm), and the evening price (5 pm to 12 AM) was 107% higher than the price for solar hours.

Figure 11: Weighted average hourly power exchange prices for FY24



Note: Based on the unconstrained volume and market clearing price in each 15-minute block for all bid areas in FY24 on the India Energy Exchange, which accounts for 90% of the exchange-related trades in Indian electricity markets. The day ahead market has the highest liquidity, and this is reflective of the variation in marginal price on a 15-minute/hourly basis.

In FY24, an average annual market clearing price of ₹3.1 per unit was observed during solar hours when power is injected. With the market price variation observed, this implies an additional cost varying between ₹1 per unit and ₹3 per unit during non-solar hours for DISCOMs, which could also represent the banking cost per unit of the energy off-set.

However, although banking costs could vary between ₹1.1 and ₹3.3 per unit of energy banked, the actual banking charge is only about 8% in kind on energy banked, which translates to approximately ₹0.25 per unit of surplus injected and later drawn. This is highly concessional given the actual cost. Gujarat is an exception, charging ₹1.25 per unit of solar energy consumed for all banking services, irrespective of the actual energy banked.

In order to manage procurement requirements, almost all states have implemented restrictions that prevent energy injected in off-peak periods from being offset against consumption during peak periods. Though such restrictions limit the quantum of banking, the cost of banking, when provided is substantially higher than the banking charge.

An independent study conducted for the regulatory commission in Karnataka estimated the cost of banking at ₹0.60 per unit of energy wheeled for open access/captive consumers in FY21 (PEG, 2022). By way of comparison, this is equivalent to double the wheeling charges that DISCOMs levy for using their network. According to the study's analysis, the current banking charge is approximately 60% lower than the actual cost of banking. This gap is expected to widen in the future due to higher renewable energy penetration and rising power costs during non-solar hours.

Several DISCOMs have previously approached regulatory commissions seeking compensatory banking charges. For instance, in 2018, TANGEDCO in Tamil Nadu estimated that with regulated charges of 12% of energy banked, the DISCOM incurred losses of ₹0.73 per unit of energy banked (TNERC, 2018). This was challenged before APTEL, which directed the State Commission to conduct a detailed study on banking costs in 2021 (APTEL, 2021). However, this study has not yet been completed (APTEL, 2025a).

Similarly, in Case No. 85 of 2017, Maharashtra's MSEDCL estimated the banking charge at ₹0.68 per unit of energy banked (equivalent to approximately 20% in-kind of energy banked) while proposing a revision in banking charges (MERC, 2019). The petition was rejected, and the banking charge has remained at 8% in-kind of energy banked since 2023.

In Andhra Pradesh, within the existing banking framework, if 30% of consumers migrate to captive sources and use banking, the DISCOMs lose about ₹600 crore per year given the existing banking charges.[76] This is also an underestimate because the quantum of banking is projected to increase rapidly with the growing number of consumers under Green Open Access and the cost of banking is set to increase with widening price differentials between solar and non-solar periods in the future.

In some states the restrictions on banking by DISCOMs and SERCs are more severe. In Punjab in addition to peak restrictions, off-set is not allowed during the any period in the peak demand months between June and October (PSPCL, 2024). Maharashtra has recently restricted banking only to solar hours (MERC, 2025). Although these restrictions help DISCOMs manage power procurement, they also limit consumers' ability—particularly small consumers—to access reliable renewable power. Bridging this gap may require either providing the banking service at cost or enabling better access to market-based reliability solutions.

C&I consumers with rooftop solar installations under the net metering framework also utilize banking services, but in most states, these services are provided free of charge without any peak-period restrictions. As rooftop solar installations increase, compensatory charges need to be developed for the services provided to these consumers. However, such a framework would require careful calibration based on several factors: the size of consumers, the presence of advanced metering infrastructure capable of 15-minute or hourly energy accounting, and the availability of communication protocols to manage and schedule power injection and withdrawal.

[76] This is estimated assuming the prevailing restrictions on banking across ToD slots and assuming that the surplus injected is valued at ₹3 per unit and that the drawal units offset are valued at the market price at the time of drawal. Block-wise industrial consumer load shapes for Andhra Pradesh are based on PIER estimates (PEG, 2025b).

Pricing challenges also exist with standby services, where current charges may not adequately reflect the true cost of providing backup power. Planned standby—where 24 hours' notice is given—is charged at the same rate as regulated tariffs, while unplanned standby services are charged 25% higher than regulated tariffs. However, it may be significantly more expensive for DISCOMs to plan procurement at short notice and at scale. The actual cost and financial loss are difficult to estimate without understanding the specific instances where standby is utilised.

Recognising these price and service cost misalignments, two states have developed service-based pricing approaches for standby. Punjab and Maharashtra have implemented multi-tiered standby charge structures that include monthly commitment/subscription fees regardless of standby usage, along with separate charges for planned and unplanned standby services (MERC, 2020; PSPCL, 2024). This service-based distinction would help DISCOMs to better manage costs and operational planning.

As mentioned earlier, CSS and AS levied on open access consumers were designed to compensate them for revenue loss and power purchase costs resulting from sales migration. To that extent, these charges also compensate for the reliability services provided by DISCOMs. However, most migration occurs through captive routes where such charges are not levied and this—combined with concessional services for captive consumers—adversely affects DISCOMs' finances.

In some states (for example, Maharashtra), captive consumers pay higher electricity duty than open access consumers, whereas in others they pay lower rates (for example, Andhra Pradesh). If cross-subsidy surcharge and additional surcharge were made applicable to captive consumers and electricity duties were rationalised to be the same for open access and captive consumers, DISCOMs could potentially earn additional revenue of approximately ₹28,500 crore per year (see Annexure 12). This is indicative of the notional annual revenue loss of DISCOMs due to the non-application of open access charges.

Perhaps such losses explain the several administrative and procedural barriers to adopting open access in all states. These barriers deter small and medium enterprises from using competitive supply through such routes. Therefore, cost-compensatory charges for DISCOM services and the availability of market-based alternatives to the reliability services provided by the DISCOM is a vital aspect of providing competitive and reliable supply to Indian electricity consumers.

7.6 Several efforts underway to deepen electricity markets but liquidity remains a challenge

India's electricity market operates under a fragmented structure where transparent, centralised competitive trading remains confined to short-term contracts of less than one year's duration. Long-term power procurement by DISCOMs follows stipulated competitive bidding processes or is under cost-plus procurement procedures at the DISCOM level. To secure long-term contracts, open access and captive consumers navigate fragmented markets characterised by significant information asymmetries that impede efficient price discovery. This is due the absence of centralised, robust or large markets for long-term contracts which is accessible to consumers. In FY24, electricity traded in India's centralised, transparent short-term markets accounted for approximately 11% of electricity generation.[77] Within this segment, trading occurs through two primary channels: power exchanges, which facilitated 63% of short-term transactions, and bilateral contracts, representing the remaining 37% (CERC, 2025).

Bilateral contracts are mostly managed through the DEEP platform by central government agencies. Under this framework, DISCOMs procure short-term power through reverse auction processes designed for transparent price discovery, as per short-term bidding guidelines notified by the MoP (MoP, 2016).

Three power exchanges currently operate in India. Almost half of the volume of power exchange trades occurs through day ahead market contracts using closed-door, double-sided auctions for price discovery. Day ahead contracts, in existence since 2008, represent the most mature and liquid contract type on power exchanges. The real-time market (RTM), introduced in 2020, has rapidly gained significance and now represents one-third of power exchange volumes. RTM contracts feature a bidding-to-delivery cycle of 1.5 hours, also employing closed-door, double-sided auction mechanisms. This market segment addresses immediate balancing needs and provides flexibility to manage requirements closer to actual delivery.

In 2021, the Central Electricity Regulatory Commission (CERC) introduced green trading mechanisms within the day ahead market to address the growing renewable energy penetration and support compliance with renewable purchase obligations. The green buy and sell bids are cleared together to discover green market clearing price in the integrated day ahead market, enabling DISCOMs and other consumers to fulfil both voluntary commitments and mandatory renewable procurement requirements. Green trades represented 4% of the total day ahead market transactions in FY24.

Another development in 2021 was the introduction of over the counter (OTC) trading platforms. These electronic platforms are for exchange of information among the buyers and sellers of electricity to enable bilateral trading with less information asymmetry. This was intended to enable flexible trading options and to set up integrated platforms where open access consumers could also trade, because the DEEP portal is meant only for DISCOMs.

Until 2021, power exchanges were only allowed to offer forward contracts where the delivery date was within 11 days of the transaction date. This was due to lack of jurisdictional clarity on the regulatory authority for electricity forwards and futures. With the Supreme Court judgement in the matter in 2021, it was clarified that the CERC would be the regulator for non-transferable, specific delivery contracts, thereby enabling power exchanges to introduce forward contracts with longer durations (PIB, 2021). It was also clarified that SEBI would regulate any electricity derivatives. In June 2022, the CERC approved the introduction of forward contracts of up to 3 months ahead (including dedicated green contracts). All three exchanges currently offer weekly, monthly and daily forward contracts of up to 3 months ahead. These contracts accounted for 16% of the total trades in power exchanges in FY24.

In 2025, three major developments took place which have the potential to significantly accelerate market participation:

— First, in July 2025, the CERC initiated a process to implement market coupling in a phased manner (CERC, 2025). This implies a unified price clearing process for all three exchanges

[77] For the purpose of this study, electricity transacted under the Deviation Settlement Mechanism (DSM) is not considered a market trade. This is because DSM, rather than a market contract, is primarily a regulatory framework and grid discipline tool, with incentives and penalties designed to maintain grid frequency.

handled by a single Market Coupling Operator rather than the current practice of three separate price clearings. Prima facie, this has the potential to reduce market fragmentation, standardise products and increase liquidity.

— Second, following SEBI approval, the Multi Commodity Exchange of India Ltd (MCX) and the National Stock Exchange (NSE Ltd) launched electricity futures/derivative contracts in July 2025. The cash-settled contracts are linked to the volume-weighted average monthly market clearing price in the day ahead markets of IEX for MCX and PXIL for NSE. Contracts are available for the current and upcoming three months on a rolling basis.
— Third, at the time of writing this report, the CERC is considering providing regulatory approval for virtual power purchase agreements (VPPAs), bilateral financial contracts which can be used by consumers to meet their renewable energy commitments. Under such contracts, the renewable energy generator can sell physical power to the market as long as the VPPA buyer is given the green attribute at the pre-agreed price (CERC, 2025).

These market developments support the potential expansion of competitive procurement options for non-DISCOM consumers, offering transparent mechanisms to secure supply and other reliability services. Market growth prospects would improve significantly if term-ahead markets evolve to include medium-term contracts and exchanges adopt standardized contract structures.

However, realizing this potential critically depends on enabling frameworks that facilitate expanded open access and captive consumer participation. The current market composition reveals DISCOM dominance, with open access consumers accounting for only 12% of total energy traded in the day-ahead market segment.

This limited participation reflects existing regulatory frameworks: resource adequacy guidelines and regulations mandate that DISCOMs procure 90% of their power requirements through long-term contracts, restricting short-term procurement to 10% or less of their total portfolio. Consequently, sustainable market expansion cannot rely solely on growth in DISCOM procurement. Without corresponding increases in open access and captive consumer participation, the overall market size faces inherent growth limitations.

The trends analysed in this chapter—particularly the evolving DISCOM tariff structures, cost reduction opportunities through renewable energy and storage technologies and expanded access to competitive markets are disruptive, ongoing and inevitable. However, they also present transformative potential for India's electricity sector. Given the substantial financial implications of these developments, it is in the sector’s interest that a phase-wise plan to manage the impact of these trends is devised. The following chapter details a potential approach alongside necessary adaptations in DISCOMs’ roles and business models to ensure future-ready operational frameworks.

Key takeaways

— DISCOMs in India are already facing disruptive shifts which will fundamentally affect the structure of the electricity sector and their future business model. Although these trends challenge the traditional business model of DISCOMs, they also create opportunities for DISCOMs to redefine their roles. Because some of these changes are inevitable, not addressing them in a systematic manner would adversely affect the future financial position of DISCOMs.

- **Cross-subsidies not a major contributor to DISCOM revenues**: Traditionally, DISCOMs relied heavily on cross-subsidies to provide tariff support to the residential and agricultural categories. However, with increasing open access and captive sales and regulatory steps to reduce cross-subsidy in tariffs, cross-subsidies now account for less than 10% of revenues. At the same time, direct state subsidies contribute between 10% and 47%. This increasing dependence on state budgets raises questions of fiscal sustainability and alters the political economy of tariff design. However, reduced reliance on cross-subsidies changes the traditional structure in which retaining typically cross-subsidising C&I consumers was vital the financial viability of DISCOMs.
- **Rapid scaling of agricultural solarisation is being adopted by various states**: As discussed in the previous chapter, agricultural solarisation has significant potential to reduce cost and subsidies. Maharashtra, Gujarat, Rajasthan and Andhra Pradesh are rapidly scaling feeder-level and centralised solar capacity to meet agricultural demand. Maharashtra alone has contracted nearly 18.7 GW, covering around 85% of its agricultural consumption and saving ₹4,000 to 5,000 crore annually for the DISCOM and the state governments. The fact that majority of this capacity was contracted within a nine-month period is evidence for the rapid scalability potential of the model. The state has also coupled solarisation with decentralised storage investments to improve reliability and financial savings
- **Sharp decline in storage cost is enabling RE integration and consumer choice**: In the past two years, the cost of storage technologies, especially battery storage, has fallen rapidly. Solar-plus-storage options to meet more than 90% of an industrial consumer’s demand are now available at less than ₹6 per unit, which is lower than the energy charges for industrial consumers in 21 of 28 states. This economic imperative deepens the trend of C&I sales migration.
- **Significant dependence of C&I consumers on non-DISCOM supply through RE captive which is bound to grow in the future**: In Karnataka, Tamil Nadu, Gujarat and Madhya Pradesh, 15% to 60% of C&I demand is already met through captive and open access routes. In Karnataka, Tamil Nadu and Maharashtra, the bulk of these non-DISCOM sales reported by the DISCOMs are attributable to renewable-energy-based captive supply. This indicates that future migration will be driven by captive and renewable energy having implications on revenue recovery and managing power procurement planning and costs for DISCOMs.
- **DISCOM reliability services for migrating consumers are underpriced, leading to losses**: DISCOMs are currently the only providers for reliability services (banking and standby) to open access and captive consumers. However, these services are priced far below cost. Even with under-pricing, DISCOMs would have been compensated with open access charges. However, captive users are exempt from open access charges, leading to notional revenue losses of around ₹28,500 crore annually for DISCOMs. As volume of captive sales increase, DISCOM losses are bound to increase without adequate compensation for services. Therefore, there is a need for pricing reform for DISCOM services and development of reliable, robust options for consumers to avail such services through market options.
- **Several initiatives undertaken for electricity market development**: Finally, electricity markets are slowly expanding, but liquidity remains limited. Short-term markets account for just 11% of the total power traded, with DISCOMs still the dominant buyers. New developments such as market coupling, electricity futures and even virtual PPAs are on the horizon, but their success will depend on stronger open access participation and standardised medium-term contracts.

Together, these emerging trends suggest that the traditional DISCOM model will come under growing strain, but also point to opportunities for redefinition — from a revenue-dependent supplier to a more resilient role as network operator, service provider, and market facilitator. Without this change in role, the financial impacts on DISCOMs would be unavoidable and substantial.

Recommendations:

— The level of cross-subsidy surcharge and additional surcharge needs to be reevaluated, given that their underlying rationale—cross-subsidy revenue loss and cost compensation for under-utilization respectively—is less relevant now. Instead, these charges could be replaced with a supply obligation charge levied on open access consumers, captive consumers, and net metering consumers alike as all of these consumers would be using DISCOM reliability services.

— The charge could be structured as either a per-unit consumption charge or a per-kW charge levied on non-DISCOM capacity contracted. The charge itself can vary based on consumer size and the type of reliability services utilized. Going forward, other more dynamic and real-time cost-compensation mechanisms need to be developed depending on the specific services provided and the available metering infrastructure.

— DISCOM procurement planning must incorporate the risks of large scale migration of consumers to open access especially with accelerated RE and storage adoption. In fact, contracts or agreements for supply with consumers can be structured to clearly state the price for services (at cost-reflective rates) as well as the duration for those services. This is currently not the case the as the pricing is bundled with consumer tariffs.

— States must address implementation aspects which hinder rapid adoption of solar for agriculture and evolve state specific models that will address developer risks, land availability concerns, socio-political contexts, the distribution infrastructure pre-requisites as is the case in Maharashtra. This can also be through state specific schemes.

— Many of the trends described in the chapter are ongoing and likely irreversible. State Governments and DISCOMs should evolve a comprehensive ten year vision for the sector to address these trends from a long-term perspective which protects the DISCOM from undue financial impacts and also fosters competitive electricity supply options and market participation of enterprises in the state. The vision document itself can be reviewed every three years to account for techno-economic changes in the sector. To prevent the risk of stranded/ under-utilised assets, future procurement and investment decisions and medium-term plans must also be linked to this vision document.

8 A proposal for increasing competitive pricing and deregulation of the electricity sector

8.1 Overview of key converging trends necessitating deregulation of HT supply

The trends discussed in the previous chapter fundamentally challenge the existing roles and business models of DISCOMs, pointing towards a sector-wide structural transformation and transition in India's electricity sector. This transformation is driven by **key trends** that together create a compelling case for transitioning HT consumers from administrative operations and cost-plus regulated tariffs to a market-based pricing framework. Because these trends are driven by techno-economic shifts, rapid non-DISCOM procurement by consumers can either play out chaotically with significant adverse financial impacts on DISCOMs or can be managed in a phase-wise manner through policy interventions to benefit the power sector at large.

First, evidence suggests that cross-subsidies from C&I consumers are not as critical to DISCOM revenue sustainability as has been traditionally assumed. This finding has important implications: if C&I consumer migration does not permanently undermine DISCOM finances or small consumer affordability, the rationale for keeping them within the regulated framework weakens. The focus should instead shift to reform of electricity pricing, especially regarding sales migration charges, such that DISCOMs are compensated for providing reliability services rather than imposing surcharges tied to cross-subsidies.

Second, the rapid scaling potential of agricultural solarisation—capable of meeting 90% or more of daytime agricultural demand within 2-3 years using low-cost solar power—presents an opportunity to fundamentally restructure subsidy requirements. This transformation would not only reduce electricity costs but also reduce both direct subsidies and cross-subsidy dependencies, concentrating financial support mechanisms and supply efforts in non-solar hours primarily on residential consumers in the LT segment.

Third, with solar-plus-storage solutions increasingly becoming competitive with DISCOM supply costs, C&I consumers face strong economic incentives to pursue alternative or non-DISCOM supply sources. The primary barriers are no longer technological or economic, but administrative and procedural constraints that limit non-DISCOM procurement. Concessional, regulated reliability service provision by DISCOMs results in financial losses for and constraints development of long-term alternative reliability arrangements for consumers.

Fourth, with increasing sales migration, DISCOMs are faced with demand uncertainty, making future power procurement planning challenging. Consumers opportunistically switch between DISCOMs and captive sources and rely heavily on DISCOMs to provide reliability services at short notice at concessional rates. Unless market alternatives are developed to provide these services or DISCOMs charge for these services at cost, the financial implications of planning for procurement to meet reliability requirements and the uncertain demand from these consumers can lead to significant strain on power procurement costs and also increase the risk of unutilised/underutilised contracted capacity. This will have severe adverse implications on DISCOM finances.

Fifth, as mentioned in the first chapter of this report, India's HT network infrastructure has significantly improved over the past two decades. In addition, network metering is also much more robust in this segment, making it capable of managing multiple users, generators and consumers. Further improvement in metering and energy accounting is expected in the medium term with consumer smart metering, feeder metering and distribution transformer metering initiatives currently underway across DISCOMs. Moreover, several innovations in India's marginal electricity markets—including green contracts, term ahead markets, derivatives and virtual PPAs—have laid the foundation necessary for direct consumer participation and market-driven procurement.

These converging trends suggest that India stands at an inflection point where continuing with administrative and regulated power procurement and tariff for HT consumers may be unnecessary.

8.2 Core elements of Carriage and Content Separation for HT Consumers

With open access already operational, the legal, regulatory, procedural and tariff framework for non-discriminatory use of transmission and distribution networks is well established, particularly for HT consumers. Given their financial capacity and ability to procure or invest in their own supply, the time is ripe to introduce Deregulation of HT supply, that is carriage and content separation for the HT consumers. Such a move would separate supply and HT network functions essentially making DISCOMs only responsible for network operations, investment and management. For supply, HT consumers can choose from a competitive set of suppliers across the country, rather than being tied to the licensed utility operating under the cost-plus regime. This shift would enhance price discovery and accelerate renewable energy adoption as that is the cheapest supply source, as mentioned above. Therefore, a critical element in operationalising this approach is **transitioning HT supply from cost-plus tariff regime to deregulated, market-based pricing mechanisms**.

Extending such reforms to LT consumers, however, is premature, as challenges in metering, energy accounting, embedded generation management, forecasting, scheduling, and deviation settlement remains unresolved, and would be highly costly and technically challenging. In the medium-term, therefore, this transformation is best restricted to the HT segment, where the benefits of competition and choice can be realised without overburdening the system. As per CEA, there are 8.9 lakh HT Industrial consumers in India, which accounts for 0.3% of total consumers India. However, these consumers account for about 25% consumption at the national level. Therefore, suggested approach of carriage and content separation for HT consumers can unleash large scale competition, but would be technologically and administratively much easier to implement and monitor.

However, the transition to a market-based approach, even for HT consumers, raises questions regarding grid reliability, the institutional frameworks required, mechanisms to manage market based procurement and the role of DISCOMs in this arrangement. Some proposals to address these issues are discussion in this section

To transition from monopoly service provision by DISCOMs to competitive supply arrangements for HT consumers, the proposed framework centres on five core elements that collectively address the institutional, economic and operational prerequisites required to unleash competitive forces and expand market-based procurement for consumers in India.

The first element involves creating a business and regulatory environment where **multiple supply choices for HT consumers** are available, enabling consumers to select suppliers based on price, reliability and service parameters. This would enable consumers to depend on market-based supply options to meet most of their supply and reliability requirements at market rates.

The second element requires **moving away from tariff and pricing determined by cost-plus regulation for DISCOMs towards market-based pricing** of services provided. This approach enables DISCOMs to participate in market-based provision of supply and services, freeing them from onerous regulatory approvals while subjecting their operations to competitive pressures.

An integrated and planned network for transmission and distribution of power is crucial to enable multiple buyers and sellers to participate in the market. Therefore, the third element recognises that even with carriage and content separation for HT segment, the **network must remain a monopoly business with regulated tariffs**. Private investment in building networks through tariff-based competitive bidding for transmission and sub-transmission networks can be explored for timely and cost-efficient project completion. DISCOMs can also appoint franchisees on revenue-sharing models to ensure timely O&M of particular divisions/feeders. However, network ownership and planning should continue as licensed and regulated activities to capture the benefits of network effects, pooling and economies of scale.

A key element of ensuring that DISCOMs successfully transition from distribution and supply providers to network service providers is establishing a **balanced risk-reward framework** where DISCOM services are compensated at cost or market rates, while consumers are not prevented from accessing competitive services and choices. As the LT network and consumers are not subject to carriage and content separation, in the proposed approach this fourth core element protects small consumers on the LT network from DISCOM's market participation risks while enabling HT consumers to benefit from competition. Ring-fencing the regulated business from market participation is therefore a critical component of this approach.

The proposed approach, although necessary for DISCOMs to manage future disruptive trends, represents a fundamental shift in DISCOM roles. To support DISCOMs through this structural change that affects the entire sector, implementation should occur in phases. During this three-to-five-year transition period, **transition finance support, clear and certain regulatory frameworks outlining the transition process and strong institutional support** are the critical fifth element needed to provide confidence to investors, consumers and DISCOMs throughout this shift.

8.3 Competitive supply for HT consumers through Open Access and tariff deregulation

To operationalise this approach, state governments and SERCs should initiate the process for HT Deregulation or Carriage and Content separation for HT through a notification and via regulations by which all consumers connected to the HT network will transition to unregulated supply pricing within a five to seven-year period. Operationalising the approach through state government notification and SERC regulations implies voluntary adoption by states based on their context and realities. Such adoption can be incentivised as detailed later in Section 8.3.8. This change will have significant impact and requires sustained action on various interconnected aspects outlined below.

8.3.1 HT Deregulation: Non fixation of tariffs by SERC, no obligation to supply for DISCOMs

As per this approach, deregulated HT consumers will not have any regulated tariffs, for the 'supply' component, be it fixed charge, variable charge or fuel surcharge. In addition, no cross-subsidy or additional surcharge will be applicable on these consumers whether the supply is via open access or captive.

These consumers will have to arrange for supply options to meet 100% of their supply requirement through deregulated, market-based procurement.

Under this approach, DISCOMs will have no obligation to supply power to these consumers, except as provider of last resort or as standby service provider. DISCOMs can choose to provide standby services and supply services at market based, unregulated tariff. This fundamental shift from a regulated supply provider for HT consumers to an optional market participant will enable DISCOMs to focus resources on LT consumers while participating competitively in HT supply markets.

8.3.2 Regulated network services: Transmission and wheeling at cost-plus regulated tariffs

Like all open access consumers, deregulated HT consumers will be subject to network charges and applicable losses for transmission and distribution network usage. The methodology to determine these charges will be similar to that used to determine the transmission and wheeling charges for open access consumers in accordance with the existing regulations.

In the proposed approach for carriage and content separation, limited to the HT network, regulated network access is essential to enable the competitive supply options, because it ensures non-discriminatory access to the grid infrastructure while maintaining cost-recovery for network operators. The continued regulation of network planning, investment and performance is necessary for smooth grid operations, a key foundation for the development of competitive supply markets.

8.3.3 Strengthening the HT network and streamlining network access are critical

Robust and reliable networks are crucial, and towards this end, investment can be encouraged in transmission and sub-transmission networks through competitive bidding, and O&M franchisees can be appointed as discussed in Section 6.5.

State transmission utilities (STUs) and SLDCs can also be empowered to implement HT open access directly, through a smooth online process, eliminating a key bottleneck that has historically constrained open access adoption. To enable this, options to hand over the HT segment of the network owned by the state-owned DISCOM to the STU could also be explored. This could include the handing over of all assets which are 33 kV and above or 11 kV and above. In fact, to reduces losses and outage rates in the 33 kV sub-transmission system, the MoP issued an advisory in September 2021 to handover 33 kV systems with the DISCOMs to the STU. MoP suggested a phased handover, starting with existing over-loaded assets (PIB, 2021).

8.3.4 Market based reliability services but DISCOM provider of last resort at regulated rates

DISCOMs serve as providers of last resort when all other supply options fail. In such cases, premium charges at pre-stipulated, regulated rates should be levied when the service is availed which can incentivise meeting reliability requirements through market-based arrangements. The premium charge can be a per unit charge equivalent of 2 to 3 times the average cost of supply of the DISCOM.

Under this approach, DISCOMs will not provide banking or standby services at regulated, concessional tariffs. Banking, standby, peak power supply in non-solar hours and other reliability services can be obtained from DISCOMs or any market-based provider through contracts at mutually agreed or competitive/cost-reflective market prices. This market-based approach to reliability services complements the competitive supply framework by ensuring that consumers have options for managing supply risks, while creating new revenue opportunities for service providers. This opens avenues for technology-based innovation, new business models and increased investment in the sector.

8.3.5 Multiple supply options for consumers subject to compliance with grid requirements

With deregulation, HT consumers will access DISCOMs' wire networks to obtain supply from multiple options across the country, including power exchanges; directly from generators, traders and sellers on OTC platforms, the DISCOM in their area of supply or any DISCOM in the country; and their own captive plants. However, this access will be subject to compliance with connectivity, metering and scheduling requirements established under the open access framework.

With multiple options for supply, consumers can create a portfolio to meet all of their power requirements and mitigate reliability-related risks on their own. However, to ensure grid stability, compliance with existing technical requirements for open access is crucial, and processes can be streamlined to aid consumers.

8.3.6 National and state-level bulk supply licensees and standard contracts

Because market participation and liquidity require time to develop even with policy-driven demand for market-based supply services, national and state-level bulk supply licensees could be introduced. These companies (which could also include state, central or private sector generation companies and traders) could supply electricity to consumers under standard contracts. These licenses, like trading licensees should not be cost-plus business.

All Standard contracts will be similar on key aspects[78] such as default provisions, scheduling, payment security, etc., helping MSMEs and small consumers lacking expertise in electricity trading to contract supply competitively without significant transaction costs. Some contract specifications could be standardised for various types of contracts such as standard durations (weekly, monthly, quarterly, one year, five years, etc.) and the supply/reliability service provided (round-the-clock power, evening/morning/nighttime peak supply, solar/non-solar hour supply, seasonal supply, standby service, etc.). Such an approach would help consumers evaluate prices quoted for standard durations and services across contracts. All standard aspects should be as detailed by the CERC or the Forum of Regulators to ensure standardisation across the country.

Bulk supply licensees supplying power under these standard contracts can help address market liquidity concerns during the transition period of five to seven years. The standard contracts for these licensees can enable market participation of smaller HT consumers who lack sophisticated procurement capabilities.

8.3.7 Regulatory ring-fencing to protect consumers from DISCOMs' unregulated business

DISCOMs will continue providing regulated cost-plus supply and service to consumers connected to the LT network. These consumers, predominantly agricultural and residential

[78] Of course, some aspects would vary from contract to contract, such as the quantum, price, point of connectivity, contracted capacity, delivery/drawl voltage and effective date of contract.

consumers, will continue to be subject to regulated tariffs, and DISCOMs will plan power procurement only to meet the requirements of these consumers.

If DISCOMs provide supply and reliability services to deregulated consumers, any losses from their deregulated business should not be recovered from LT network consumers, who will remain subject to cost-plus regulation. This ring-fencing is essential to ensure that competitive market risks are not transferred to vulnerable consumer segments.

This ring-fencing will also ensure that support funds provided to the DISCOM for transition finance, as detailed in Section 8.3.8, would not be utilised to subsidise market losses.

8.3.8 Transition finance support

In the transition period, to support DISCOMs for revenue loss and incentivise adoption of the new approach, the central government could provide support of up to ₹1/unit each year for three years for incremental open access sales. The support would be for every unit of open access and captive sale in addition to the open access and captive sales from the previous year. This ensures that the support will be provided only when the market access of HT consumers increases rather than for just the formal adoption of the approach. Such support would also recognise that despite long-term benefits, such a fundamental shift could be disruptive for the state government and DISCOM in the short run.

Assuming 45% of HT sales measured in the base year migrates to open access in the three-year period with an incremental annual shift of 15%, the additional central government support to be provided across all states to operationalise enabling frameworks for HT deregulation would be ₹7,900 crore per year for three years. This could be enhanced depending on the states' requirements.

In addition, transition finance can be supported through a 'supply obligation charge' of ₹2.5/unit paid by all HT consumers using open access or captive sources. Such a charge should only be levied in states for the first five years where state governments enable HT deregulation. This levy could generate up to ₹53,000 crore/year of additional revenue for DISCOMs over five years. Moreover, no budgetary outgo would be required.

The supply obligation charge should subsume other charges levied on open access and captive consumers such as parallel operation charges, additional surcharge and cross-subsidy surcharge. In addition, to ensure there is no additional impact, electricity duty on open access and captive consumers should be charged on par with other HT consumers in that category. Importantly, because the surcharge is only for transition finance support, it should be discontinued after a five-year period to incentivise DISCOMs to be accountable and take responsibility for improving efficiency.

This transition finance is crucial because it provides DISCOMs the financial cushion needed to protect small consumers from tariff shocks and provide reliable supply while developing the capabilities to compete in the deregulated market segments described in Sections 8.3.4, 8.3.5 and 8.3.6.

8.3.9 The changing roles of DISCOMs and regulators

This approach would transform the distribution companies from today's DISCOMs to tomorrow's network companies (NETCOMs). The DISCOMs' role would change to:

— Serving as the primary supplier for all consumers to supplying only LT network consumers at regulated tariffs.
— Having no obligation to procure power for HT consumers but could choose to provide supply and reliability services at market/cost-reflective rates
— Providers of last resort for HT consumers at premium regulated tariffs, which is equivalent of 2-3 times the DISCOM's ACOS.

However, DISCOMs would continue as network service providers, along with transmission companies, at regulated tariffs.

For DISCOMs, this approach would help rationalise power procurement by reducing demand uncertainty, enabling market-based pricing of services. This approach would also enable DISCOMs to focus on the concerns of small LT consumers regarding reliability and supply.

For HT consumers accounting for 35% of DISCOM sales, this approach would provide freedom and choice to obtain competitive tariffs within a five- to seven-year period. It would also provide certainty in frameworks and approaches and ease operational processes for obtaining open access, which have been slow to evolve. With the majority of agricultural consumer demand being aligned to solar hours in the future, the primary role of DISCOMs would be to manage the network and the supply requirements for LT C&I consumers as well as residential consumers. Here, measures to assess supply quality, HT and LT network service quality and actions to ensure performance accountability for DISCOM services would become crucial.

For regulators, the deregulation approach would change their role to formulating appropriate frameworks for market development, protecting small consumer interests, aiding appropriate network planning, ensuring accountability for supply and service quality, regulating capital investment in networks, approving standard provisions for bulk supply contracts, streamlining open access and fostering competition.

8.3.10 Complementary and supplementary efforts needed

Complementary efforts required for this approach's success include creating strong and independent institutions for grid operations, especially to manage multiple grid users, their scheduling, energy accounting and deviation settlement. Improved measures for network planning, investment and maintenance, and better integration and information sharing across fragmented markets are equally essential.

Over time, competitive supply options should be extended to LT consumers. Within the existing regulatory regimes, options using grid interactive renewable energy with net metering and net billing arrangements could be provided to LT consumers to enable them to obtain competitive supply, provided the regulatory frameworks ensure that DISCOMs will be compensated for services without adversely affecting very small consumers (those with demand less than 3 kW). With the successful implementation of HT deregulation and improved LT metering infrastructure, more consumers would be able to access competitive options through demand aggregation measures.

To provide centralised supply options with transparent price discovery, power exchanges can have standardised, transparent double sided auctions for price discovery for contracts other than Day Ahead Markets and Real Time Markets. This could also help increase liquidity in markets and lead to efficient price discovery.

Additionally, frameworks ensuring cost recovery by DISCOMs are critical, especially during the five- to seven-year transition period. This is why measures related to ToD tariffs, inflation-linked tariffs for LT consumers and cost-reflective services for HT consumers become crucial.

The aspects of the proposed approach to operationalise HT deregulation or carriage and content separation in summarised in Figure 12.

This fundamental change offers the potential benefits of cost reduction and reduces power procurement planning risk for DISCOMs, with the possibility of additional revenue generation through market participation. The proposed approach would translate to significant increases in choice and services available to India's growth engine: its enterprises. Without this approach or another suitable approach to address the challenges associated with sales migration discussed in Chapters 7, DISCOMs might face new challenges to financial viability, creating the grounds for future bailouts.

Figure 12:Aspects of proposed carriage and content separation for HT consumers

PROPOSAL FOR HT SUPPLY DEREGULATION / CARRIAGE AND CONTENT SEPARATION FOR HT SUPPLY

No Regulated Tariffs for HT Supply: With 3 to 5 years advance notice, SERCs stop tariff determination for HT supply. HT Consumers find suppliers at negotiated tariffs. The change can take place via voluntary adoption by state government, SERCs.

Network to remain monopoly business: Transmission and distribution business remain cost-plus, with regulated tariffs for network services (wheeling, transmission).

Consumers can choose supplier: Can be from generators, traders, exchanges under open access. National/State Bulk suppliers trading via standardised contracts can be instituted. Need for simplified processes and removal of administrative barriers.

Balanced, risk-reward framework: DISCOMs compensated for services such as standby, banking, and provider of last resort.

Ring-fencing of regulated business: SERCs to ensure that costs of DISCOM's unregulated HT supply is not be passed onto LT consumers.

Transition finance support for 5 year period: The support to DISCOMs can be through a combination of supply obligation charge on HT consumers and government support.

Benefits

- Competitive choice for 25% to 35% of sales
- Supply based on market forces rather than administrative considerations
- Increased innovation in power procurement
- DISCOMs supply obligation only to LT, limiting future cost increase
- DISCOMs focus on network investments and service

Complementary Actions

- Strong institution for grid operations
- Accountability for service quality
- Cost-reflective frameworks for net metering/ net billing
- Inflation linked tariffs, renewables responsive Time of Day tariffs.
- Standard contracts on power exchanges
- O&M network franchisees, competitive bidding for sub-transmission assets

Key takeaways

- Four key trends, which were also discussed in Chapter 7, create a compelling case for transitioning HT consumers from administrative regulation to market-based procurement:
  - Cross-subsidy from C&I consumers is no longer a major contributor to DISCOM revenue.
  - The ability and appetite of C&I consumers to invest in renewable-energy-based own supply is substantial and growing, fuelled by the falling costs of solar and storage and an enabling legal/regulatory framework.
  - The past two decades have seen significant improvement in network reliability and metering infrastructure, especially in the case of the HT network.
  - Technology changes, the investment scenario and market developments make sales migration inevitable, and it can disrupt DISCOM finances.

- To transition from monopoly service provision by DISCOMs to competitive supply arrangements, where cost efficiency and service quality drive competition, the following elements are crucial:
  - Provision of multiple supply choices for HT consumers.
  - Shift from cost-plus tariffs to market-based pricing such that DISCOMs compete with market providers to cater to supply and reliability services required by HT consumers.
  - Transmission and distribution networks remain as regulated monopolies whose services are available at the payment of regulated transmission and wheeling charges.
  - Formulation of a balanced risk-reward framework which fairly compensates DISCOMs, protects small consumers and provides access and choice to large consumers.
  - Facilitative elements from the state and central governments, such as transition finance, clear regulatory frameworks and institutional support.

- Operationalising a shift in DISCOMs' business model would require the following steps:
  - State governments and SERCs can initiate HT deregulation mandating that all HT consumers should transition to competitive, unregulated supply options within five to seven years.
  - Under this arrangement, SERCs would stop fixing HT supply tariffs, DISCOMs would have no supply obligation for HT consumers and these consumers would have to procure 100% of their needs through market-based contracts.
  - DISCOMs may supply to these consumers at negotiated rates, but their primary focus would shift to LT consumers. A strict regulatory ring-fence must ensure that LT consumers are protected—DISCOMs' unregulated business risks cannot be recovered through regulated tariffs.
  - Consumers would continue to pay regulated network charges for transmission and wheeling. For reliability, DISCOMs would act only as providers of last resort at premium regulated tariffs (e.g., 2 to 3 times the DISCOMs ACOS). All other services—banking, standby, storage—must be sourced through market contracts at competitive rates, opening opportunities for new business models.
  - Consumers gain access to multiple supply options (generators, exchanges, OTC trades, captive, DISCOMs) subject to compliance with grid connectivity, metering and scheduling rules. To strengthen access, STUs/SLDCs could be empowered to

process open access applications directly, potentially transferring HT assets from DISCOMs to STUs.
  - To ease market participation, bulk supply licensees could be introduced at the national and state levels, offering standardised contracts (fixed durations, service types, payment/security terms). This would reduce transaction costs and enable smaller HT consumers to participate.

— To cushion revenue losses in the initial years and incentivise adoption, transition finance support could be provided:
  - Central government grants of up to ₹1/unit for three years for incremental open access sales (approximately ₹7,900 crore/year for three years).
  - A supply obligation charge of ₹2.5/unit on open access and captive HT consumers, replacing current surcharges and expiring after five years, potentially yielding ₹53,000 crore/year for five years for DISCOMs without no budgetary outgo.

This approach recasts DISCOMs as NETCOMs with obligations only towards LT consumers at regulated tariffs. The regulators' role shifts to market development, LT consumer protection and network oversight. Over time, competitive supply options could be extended to LT consumers, particularly with renewable integration and advanced metering. Such an approach would mitigate the power procurement planning risks faced by DISCOMs in the context of uncertainty in future demand and provide a clear framework for DISCOMs' roles and services.

Recommendations:

— State governments to consider deregulation of HT supply as one of the potential options for structural change in the sector in their 10-year plan, discussed in Chapter 7.

— Adopters of the HT deregulation approach to be provided transition finance support by the central government in the form of grants of up to ₹1/unit for three years for incremental open access sales (approximately ₹7,900 crore/year at the national level).

— State governments to levy a supply obligation charge of ₹2.5/unit on open access and captive HT consumers, replacing current surcharges and expiring after five years, potentially yielding ₹53,000 crore/year for DISCOMs to manage revenue loss during the transition period.

9 Recommendations

9.1 The overall approach

The financial challenges of DISCOMs require urgent near-term interventions to ensure the viability and health of the sector. This urgency stems from DISCOMs' continuing critical role as India's primary distribution network providers, sole suppliers to small and agricultural consumers and key facilitators of technology adoption in the energy transition. Between FY22 and FY30, these utilities are expected to enable ₹46.9 lakh crore of private and public sector investment, making their financial health of paramount importance.

Without fiscal support to address the accumulated financial losses of ₹7.08 lakh crore (as on 31st March 2024) and national frameworks of incentives and schemes to address their annual losses—about 3.6% of expenses—DISCOMs will remain trapped in a cycle of high dependence on working capital liabilities.

Currently, DISCOMs rely heavily on working capital loans to meet payment obligations to generators and transmission companies while providing reliable supply to consumers. About 44 to 86% of total borrowings by the DISCOMs in eight states[79] is reported to have been for non-capex end-use resulting in interest expenses to the tune of 5% of the DISCOMs' annual expenses each year. The DISCOMs in these eight states account for 43% of accumulated losses. It Is highly likely that such dependence is also relevant for other DISCOMs in India. This reliance on working capital borrowing creates a cascading effect: sustained dependence on central grants for capital investment, reduced resources for network maintenance and upgrades, and a mounting interest burden that further weakens the financial health of DISCOMs.

The scale and interconnected nature of the challenge demands action across five critical areas:

— Addressing the accumulated past losses and liabilities
— Preventing build-up of future losses
— Supporting DISCOMs' requirement of capital investment in the medium term
— Strengthening APTEL as an institution for swift resolution of tariff-related disputes, thereby facilitating timely cost recovery
— Supporting structural measures towards larger reform to increase competition and least-cost operations

The path forward requires treating the financial recovery of DISCOMs as a strategic enabler of India's energy transition and economic growth objectives. All major financial challenges must be addressed within a coordinated five-to seven year framework to ensure the financial sustainability of the sector. Piecemeal approaches addressing individual components will yield suboptimal results and fail to break the cycle of financial distress.

Therefore, tackling the legacy losses and liabilities of cash-strapped DISCOMs must be complemented by measures to reduce operational cost, increase capital investment and improve timely revenue recovery through cost-reflective tariffs. To this end, strengthening the effectiveness of institutions such as APTEL is critical to resolve tariff-related matters and enhance the accountability of DISCOMs. Further, DISCOMs need to be prepared for a future characterised by high renewable energy use, with more and more consumers investing in their

[79] Andhra Pradesh, Bihar, Haryana, Karnataka, Maharashtra, Punjab, Rajasthan and Telangana.

own supply. Structural measures that help DISCOMs adapt to this future are as critical as improving operational performance.

9.2 Addressing past losses and liabilities

9.2.1 Takeover of liabilities by state governments

As discussed in Section 5.1.2, it is necessary for a large part of the identified working capital liabilities of state DISCOMs to be taken over by the respective state governments through dedicated 20-year bonds, perhaps over a five-year issuance period. Similar to UDAY bonds, these instruments could be backed by state government guarantees. The coupon rates could be set at the State Government securities rates plus a 0.75% spread (0.5% base spread + 0.25% for non-SLR status) or the prevailing market-determined rates, whichever is lower. The takeover of losses could be either a one-time exercise or tranche-wise, spread over a three- to five-year period:

***One-time takeover*:** State governments could undertake complete liability takeover through 20-year bond financing in a one-time restructuring exercise. However, the takeover must be subject to strong conditionalities aimed at sustained operational improvements. This approach might be suitable for states with limited liabilities and state governments that are strategically motivated to turn around state-owned DISCOMs financially.

***Tranche-wise takeover*:** Each tranche could be contingent upon meeting mandatory performance conditions. This approach maintains continuous accountability pressure on DISCOMs, accommodates states with constrained fiscal space while ensuring reform momentum. It also allows for course correction and performance monitoring throughout the implementation period. Some of the performance conditions which can be considered for this approach are detailed later. (see Section 9.2.2).

Structure of debt takeover

The debt takeover could be structured as grants or equity infusion to DISCOMs in order to strengthen their balance sheets. Further, the scheme could also clarify that recognised/approved regulatory assets can be adjusted with the debt takeover equivalent of the grant or equity transfer value. This would enable consumers to benefit from some of the impact of debt takeover,[80] besides reducing regulatory ambiguity and preventing unnecessary litigation related to the adjustment of regulatory assets with debt takeover.

Specific restructuring terms and conditions should ideally be decided through consultations with the respective state government and DISCOMs, in view of specific contexts, fiscal capacities and DISCOMs' operational constraints.

9.2.2 Performance-linked conditionalities for debt takeover

Whether one-time restructuring or phased takeover is chosen, DISCOMs should be subject to performance- and reform-linked conditions.

To be eligible for the scheme itself, state governments and regulatory commissions should have put in place a framework for automatic levy of inflation-linked tariffs. This is particularly

[80] This approach was operationalised by regulatory commissions in Uttar Pradesh, Rajasthan, Telangana, Madhya Pradesh and Tamil Nadu. However, the non-standardised treatment and netting of not just debt and equity but also takeover transferred as loans led to several challenges with regulatory accounting.

relevant for participating states where the *approved* regulatory assets/cumulative revenue gaps are greater than 3% of ARR[81] or for DISCOMs where more than 50% of total borrowing is for working capital requirements.

In addition, state governments and DISCOMs should commit to aligning supply hours for agriculture with solar hours. This is necessary for rapid solarisation of agricultural consumption, which could result in substantial cost and subsidy savings.

To ensure continued payment discipline, state governments and regulators should also evolve clear frameworks and time-bound schedules for payment of dues to state-owned generators and transmission companies. Further, state governments must ensure timely payment of subsidies and government dues, with mandatory quarterly statements on status being reported by DISCOMs to the central government and SERCs. These reports should also be available in the public domain.

State governments along with DISCOMs should evolve a five year plan/power sector policy to reduce the revenue gap gap, rationalise electricity subsidy and implement cost-reflective tariffs. The plan, in accordance with existing legislative frameworks, could include the following elements:

— Plans to reduce the cost of power purchases, especially by integrating more renewable energy and using storage technologies.
— A trajectory for agricultural solarisation that results in 50–85% of the states' agricultural consumption being met through solar power by 2032.
— Frameworks for levying fuel surcharges and for aligning time of day tariffs with the availability of renewable energy for all non-agricultural consumers in a phased manner.
— Evolving cost-reflective, non-concessional tariff frameworks for services provided by DISCOMs to captive, open access and net metering/net billing consumers.
— Easing the processes for obtaining captive, open access and net metering/net billing for eligible consumers.
— Formulating circle-wise network investment plans along with plans to increase private capital investment in critical transmission and distribution works.

To be eligible for annual incentives from the central government or to qualify for the next tranche of debt takeover, as the case may be, DISCOMs need to demonstrate compliance and progress vis-à-vis the committed trajectories outlined in the five year plan.

State-wise quarterly updates and reports (including spreadsheets) submitted by the DISCOMs and state governments on progress vis-à-vis the plan should be hosted on a web-portal managed by MoP to facilitate public access and accountability.[82]

9.2.3 Estimated impact of debt/loss takeover[83]

In the absence of specific data on eligible liabilities, the magnitude of the fiscal impact is estimated based on takeover of total losses (both annual revenue gap and accumulated loss as

[81] The actual revenue gap as per audited accounts was around 3% of expenses in FY24. Thus, the regulatory asset build-up should be limited to not more than one year's revenue gap.
[82] This is similar to the quarterly and annual energy audit reports submitted to the BEE, which are publicly available on the BEE website.
[83] For loss takeover estimations, revenue deficit and fiscal deficit numbers are as provided by the Office of the 16th Finance Commission from State Annual Accounts. Data on GSDP is from MoSPI, and numbers on DISCOMs' accumulated deficit and the annual gap are from PFC.

of 31 March 2024). A one-time takeover of ₹7.45 lakh crore in losses across 22 states would result in an annual state government budget outlay of ₹77,000 crore, as detailed in Section 5.1.2.

As mentioned earlier, loss takeover can also be implemented through a phased approach in multiple tranches over a three- to five-year period. Conditional takeover ensures improved accountability regarding performance commitments, which was lacking in previous financial restructuring schemes. With a tranche-wise approach, the annual outgo ranges from ₹15,400 crore in Year 1 to ₹92,425 crore from Years 5 to 20. The growing economies in these states will enable them to manage the impact on their borrowing capacity. This will remain true even after the debt takeover is completed in most states, over a five-year time frame. Table 33 presents the impact of such loss takeovers on the fiscal deficit (FD) to GSDP ratio of 10 states. See Annexure 8 for the analysis covering all 22 states.

Table 33: Impact of loss takeover (tranche-wise) on FD/GSDP[84]

State	FD/GSDP		Impact of loss takeover as % of GSDP					
			Tranches					
	Existing	One-Time	Tranche 1	Tranches 1–2	Tranches 1–3	Tranches 1–4	Tranches 1–5	Tranches 1–5
	FY24	FY25	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
Unit	%	%	%	%	%	%	%	%
Tamil Nadu	3.4%	0.59%	0.12%	0.22%	0.31%	0.40%	0.47%	0.42%
Rajasthan	4.3%	0.55%	0.11%	0.20%	0.28%	0.34%	0.40%	0.35%
Madhya Pradesh	3.3%	0.52%	0.10%	0.20%	0.29%	0.37%	0.45%	0.41%
Telangana	3.4%	0.46%	0.09%	0.17%	0.25%	0.31%	0.37%	0.33%
Uttar Pradesh	3.1%	0.38%	0.08%	0.16%	0.25%	0.35%	0.45%	0.45%
Kerala	3.0%	0.29%	0.06%	0.11%	0.16%	0.19%	0.23%	0.21%
Haryana	2.9%	0.24%	0.05%	0.09%	0.13%	0.17%	0.20%	0.18%
Andhra Pradesh	4.4%	0.21%	0.04%	0.08%	0.11%	0.14%	0.16%	0.14%
Karnataka	2.6%	0.12%	0.02%	0.04%	0.06%	0.08%	0.09%	0.09%
Maharashtra	2.2%	0.09%	0.02%	0.03%	0.04%	0.05%	0.06%	0.05%

Source: Authors' analysis based on data from (PFC, 2025; RBI, 2024)

These numbers are based on takeover of losses in the absence of comprehensive data on liabilities. Because working capital borrowing data was available for eight states, the estimated impact of liability takeover for these states is presented in Tables 22 and 23 in Section 5.1.2. The annual fiscal outlay for liability takeover is likely substantially lower than loss takeover in Bihar, Haryana and Karnataka, and it remains lower but still significant in Telangana and Rajasthan. In Punjab, Andhra Pradesh and Maharashtra—where working capital borrowing exceeds accumulated losses—the annual outlay would be higher under liability takeover.

[84] The impact is estimated for the accumulated losses until FY24 and the annual revenue gap for FY24. For the purpose of this analysis, it is assumed that the first year of takeover will be FY25. For tranche-wise calculation, the GSDP projections are based on the past nominal GDSP growth rates for all years since 2011, barring the COVID-19-impacted years of FY21 and FY22. A carrying cost of 9% is assumed for estimating the carried cost on tranches until takeover.

9.2.4 Incentives provided by the central government for participation in the scheme

In order to incentivise participation in the scheme, the central government could provide the following incentives:

— Interest subvention of 1% per year for a five-year period on the bonds issued by the state government. At the national level, the impact of this interest subvention would be about ₹5,580 crore per year with a one-time restructuring. It would range from ₹1,120 crore in Year 1 to ₹6,700 crore in Year 5 with a phase-wise approach. See Annexure 14 for the state-wise details.

— An additional one-time capital investment reimbursement to the tune of 2% of the liabilities taken over can be provided to participating states. This would translate to about ₹14,900 crore in capital expenditure grants by the central government, which can be spent only on priority capital expenditure (system strengthening, loss reduction, feeder segregation, reliability improvement, etc). See Annexure 15 for more details.

9.3 Preventing build-up of future losses

State governments and DISCOMs have to commit to two major structural shifts (described below) with support from regulatory commissions. These actions together would help reduce the cost of supply in the medium term and ensure timely revenue recovery from consumers, preventing the build-up of future regulatory assets, liabilities and losses.

9.3.1 Agricultural solarisation to reduce power costs, subsidy requirement

9.3.1.1 The enabling framework

All states where agricultural sales exceed 10% of the total sales should release plans/policies with targets to solarise the majority of their agricultural consumption through centralised procurement or feeder-level solarisation by 2030[85]. This can be part of the plans/policies notified by the state government participating in the debt restructuring scheme (detailed in Section 9.2.2). The plans/policies should establish annual targets for contracting capacity through competitive bidding. This will facilitate tracking of progress by central and state governments. In line with the targets, DISCOMs could publish bidding calendars at the start of each financial year, detailing tranches of procurement planned for solarisation with clear timelines and capacity requirements.

In addition, state governments and DISCOMs must commit to aligning agricultural power supply to solar generation periods (eight hours or less) to maximise cost savings and to reduce grid balancing requirements. Further, state governments could issue detailed schemes/policies to address implementation challenges, such as off-taker risk mitigation, land identification protocols and requisite network augmentation. Such measures will help attract private participation and scale up deployment rapidly.

For feeder-level solarisation, investment in segregation of agricultural feeders is required. Progress made towards feeder segregation, where not completed, can be tracked by the state and central governments on a priority basis. Additional central sector assistance could be provided under various schemes, and feeder segregation should also be eligible for the capital reimbursement scheme detailed in Section 9.2.4.

In addition, the following measures could be taken:

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[85] Please refer Annexure 16 for share of agricultural sales in total sales across states.

— Enhanced capital support could be provided in states where agricultural demand is consistently more than 30% of sales, that is, Madhya Pradesh, Telangana, Karnataka and Rajasthan.[86]
— The central government could continue to provide financial assistance to the tune of 30% of the project cost. However, this could be limited to the first 20,000 MW of agricultural solarisation PPAs (approximately ₹21,000 crore in central grants). This would drive states to achieve early implementation milestones and incentivise rapid scaling.

DISCOMs failing to meet annual targets for feeder segregation and solarisation could lose their eligibility for performance-based incentives. In the case of tranche-wise takeover, they could also face reduction or exclusion from subsequent tranche allocations, with reductions proportionate to the severity of the shortfall.

9.3.1.2 Potential impact

Presently, solar power is available at ₹3.0–3.5 per unit at the decentralised level (33 kV/11 kV feeder level), and this competitive pricing has been achieved even without the proposed 30% central financial assistance under KUSUM C.[87] Given that the average power purchase cost (including transmission) in FY24 was ₹5.46 per unit, adopting low-cost decentralised solar would result in a 36–45% reduction in power procurement costs. This would also translate to significant subsidy savings for the state government, especially in states that supply free power to agriculture.

As detailed in Section 5.3, if 50–70% of agricultural consumers in the 12 states (which account for 97% of India's agricultural power consumption) transition to solar power, the resulting cost savings would range from ₹75,000 to ₹90,000 crore annually. This calculation is based on solar power contracted at ₹3.0–3.5 per unit (current market rates) and a conservative assumption of 2% annual growth in average power purchase costs (the actual state-level growth rates are significantly higher[88]).

Due to competitive bidding for the projects, no capital investment from the DISCOM or state government is required. The savings would be the difference between the landed cost of DISCOM contracted capacity and the price of solar power available at the feeder level. Grid-connected projects can improve their reliability and reduce their grid dependence over time with investments in tail-end storage solutions as well, which could also be procured through competitive bidding.

For reference, Table 34 shows state-specific savings for FY32 (using a conservative solar discovered tariff of ₹3.5/unit).

[86] See Annexure 15 for more details.
[87] In Maharashtra, a total of 3,706 MW of solar capacity was contracted under the solar feeder approach. These agreements were executed between FY18 and FY23 at a weighted average tariff of ₹3.18 per unit. These projects did not use 30% central financial assistance. However, central financial assistance encourages uptake and rapid scaling. In Maharashtra, 14,000 MW was contracted with central financial assistance. In Rajasthan and Gujarat, state-owned DISCOMs contracted 5,103 MW and 1,748 MW using central financial assistance.
[88] Historically, the average growth rate between FY16 and FY24 has ranged from 2.7% to 6.4% across states.

Table 34: State-specific savings from adoption of the feeder-level solarisation approach[89]

State/ UT	Agricultural consumption in FY32	Average power purchase cost (incl. Tx)		State transmission losses		Cost of grid supply at substation (FY32)	Savings due to solar feeder approach (FY32)	% of Agriculture sales solarised by FY32	Annual savings in FY32
		FY24	FY32	FY24	FY32				
Units	MU	₹/kWh		%		₹/kWh		%	₹ Cr.
Rajasthan	57,535	5.07	5.9	3.5	3.4	6.15	2.65	70%	10,668
Maharashtra	50,869	5.61	6.6	3.5	3.4	6.80	3.30	85%	14,284
Madhya Pradesh	42,703	4.98	5.8	3.5	3.4	6.04	2.54	70%	7,591
Uttar Pradesh	37,806	5.59	6.5	3.5	3.4	6.78	3.28	70%	8,679
Telangana	31,284	6.19	7.3	3.5	3.4	7.51	4.01	50%	6,268
Gujarat	28,941	5.45	6.4	3.5	3.4	6.61	3.11	70%	6,300
Karnataka	27,772	6.45	7.6	3.5	3.4	7.82	4.32	70%	8,403
Tamil Nadu	19,843	6.13	7.2	3.5	3.4	7.43	3.93	50%	3,903
Andhra Pradesh	12,946	6.29	7.4	3.5	3.4	7.63	4.13	70%	3,741
Haryana	13,644	5.42	6.4	3.5	3.4	6.57	3.07	70%	2,935
Punjab	15,618	4.48	5.2	3.5	3.4	5.43	1.93	70%	2,113
Chhattisgarh	11,643	5.59	6.5	3.5	3.4	6.78	3.28	70%	2,673
Total for 12 states	**3,50,605**		**6.50**						**77,558**

Source: Author's analysis based on data from (PFC, 2025; CEA, 2022; CEA, 2024a; PEG, 2025)

Implementing this agricultural solarisation approach has the potential to generate substantial annual savings, with benefits accruing from rapid deployment well before FY32. Implementation across the 12 states in a phase-wise manner such that 20% of agricultural

[89] The average power purchase cost (including transmission) for FY24 is as reported by PFC in the report on the performance of power utilities (PFC 2025). The escalation rates for agricultural demand are as estimated by CEA in the 20th EPS. The actuals for agricultural consumption as reported by CEA for all utilities for 2023 in the CEA Annual General Review are used for projections. State transmission losses are assumed based on the losses reported in tariff orders in various states for FY24. The trajectory for solarisation is an input or assumption based on the current status in states of feeder segregation, presence of policies to align agricultural supply with solar availability and current progress under various schemes towards agricultural solarisation.

consumption could be solarised by FY27, and so on, could deliver cumulative savings of ₹2.61 lakh crore between FY27 and FY32, as detailed in Table 35.[90]

Table 35: Year-wise savings with solarisation

Year-wise savings with agricultural solarisation approach						
State/UT	FY27	FY28	FY29	FY30	FY31	FY32
	₹ Cr.	₹ Cr.	₹ Cr.	₹ Cr.	₹ Cr.	₹ Cr.
Rajasthan	1,612	2,755	4,178	5,931	8,072	10,668
Maharashtra	9,526	10,351	11,236	12,183	13,198	14,284
Madhya Pradesh	1,286	2,149	3,185	4,420	5,878	7,591
Uttar Pradesh	687	1,549	3,053	4,908	7,174	8,679
Telangana	417	906	1,476	2,668	4,050	6,268
Gujarat	1,198	1,953	2,829	3,836	4,988	6,300
Karnataka	1,689	2,721	3,895	5,224	6,721	8,403
Tamil Nadu	261	566	922	1,665	2,524	3,903
Andhra Pradesh	725	1,177	1,697	2,292	2,971	3,741
Haryana	559	912	1,320	1,789	2,325	2,935
Punjab	412	671	967	1,305	1,686	2,113
Chhattisgarh	443	743	1,105	1,540	2,059	2,673
Total	**18,814**	**26,452**	**35,862**	**47,761**	**61,647**	**77,558**

Source: Author's analysis based on data from (PFC, 2025; CEA, 2022; CEA, 2024a; PEG, 2025)

To recap, incentives provided by the central government to facilitate rapid deployment include:

— Eligibility of feeder segregation projects for capital reimbursement incentive as part of the comprehensive package for takeover of DISCOM liabilities.
— Dedicated allocation of ₹21,000 crore of central financial assistance to support up to 30% of project cost for the first 20,000 MW of solar projects. The scheme could also be extended to storage projects co-located with solar, which would increase reliability and reliance on decentralised generation.

9.3.2 Inflation-linked tariffs

As mentioned in Section 4.3, tariff increase in most states has been infrequent and often inadequate. This is interspersed with significant tariff shock in a few years to compensate for years of cost deferral. To ensure reduced volatility and predictable tariff increase for consumers and to limit build-up of regulatory assets, state governments along with regulatory commissions and DISCOMs can institute an inflation-linked tariff framework.

[90] These projections are based on the conservative assumption that the discovered solar tariff stays at ₹3.5 per unit throughout the deployment period (despite historical declining cost trends). The actual savings potential is likely higher, given the continued downward trajectory of solar costs and potential for faster implementation with appropriate policy support.

9.3.2.1 *Instituting a regulatory framework for inflation-linked tariffs*

The framework could be introduced by state governments and regulators as part of the liability takeover scheme. The framework should be introduced in participating states where approved regulatory assets/cumulative revenue gaps exceed 3% of ARR or for DISCOMs where more than 50% of the total borrowing is for working capital requirements. The framework should also apply to states that meet these threshold conditions at any point during the five-year period of debt takeover.

The Supreme Court, in its judgement dated 6 August 2025, has highlighted the regulatory failure with long-pending regulatory assets and the danger of tariff shock on consumers (SCI, 2025). In the broader public interest and to ensure financially viable DISCOM operations, the state governments could issue policy directions to operationalise inflation-linked tariffs.[91] In addition, APTEL could also track the implementation of inflation-linked tariffs using the framework adopted by regulatory commissions under Section 121 of the Electricity Act. 2003.

9.3.2.2 *Implementation of inflation-linked tariffs*

To implement inflation-linked tariffs, SERCs should first approve cost and performance trajectories fixed for a five-year period under the Multi-Year Tariff Regime.[92] In the tariff order, applicable for the five-year period, the Commission also determines a base year tariff and an efficiency factor fixed for a five-year period. Tariffs for subsequent years can then be automatically increased by the DISCOMs from 1st April of each year. The rate of increase would be based on the inflation rate for the power sector declared by RBI or even CERC, which is adjusted with an efficiency factor fixed for five years by the regulatory commission in the Multi-Year Tariff Order. For subsidised categories, the state governments should revise the subsidy provisions as required, aligning them with the committed tariff support given the revised inflation-linked tariff. Any revenue surplus or gap should be adjusted at the end of the five-year period, when the tariff determination for the next five-year period will be considered. Such an approach can provide medium-term certainty in tariff for consumers, ensure timely revenue recovery for the DISCOM and streamline the number of cases before the regulatory commission by removing the need for an annual tariff process for tariff determination.

9.3.2.3 *Impact of the inflation-linked tariff approach*

To assess the impact of inflation-linked tariffs, we assume a scenario where the tariffs were increased at a pre-stipulated inflation-linked rate as opposed to the actual increase in tariffs in these states in the past eight-year period between 2016 and 2023 across 22 states. This is detailed in Section 5.5.1.

Under this approach, the higher revenue from inflation-linked tariffs would reduce the total revenue gap by ₹4.41 lakh crore over the period, or save the DISCOMs approximately ₹60,000 crore per year. These savings would also eliminate ₹1.6 lakh crore in interest costs during this period. The scenario assumes an average tariff increase of 3.9% across all 22 states between FY16 and FY23, which is only 0.7 percentage points higher than actual

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[91] Such tariff-related policy directions have been issued in the past and have been adopted by the Commissions. For example, the Government of Tamil Nadu in letter No.8303/C2/2023 dated 30 October 2023 issued policy directive under Section 108 of the Electricity Act, 2003 for reduction of tariff to Common facilities in multi-tenements of small apartments, following which the Commission, in Order No. 9 of 2023 dated 31 October 2023, introduced the new tariff category LT-IE with effect from 1 November 2023. This has not been challenged.

[92] The Multi-Year Tariff regulations have been notified by all SERCs, with the Forum of Regulators also issuing Model Regulations in 2011, 2023 and 2025 to aid adoption.

increase observed in this period. Thus, inflation linked tariffs would create much more stable and predictable pricing for consumers.

9.3.2.4 Additional actions required towards cost-reflective tariffs

While timely cost recovery can be instituted through inflation linked tariff as proposed, complementary measures towards cost-reflective tariffs are also necessary. The regulatory frameworks for two such mechanisms — time of day tariffs and fuel surcharge levy — are already in place in most states. However, the frameworks for time of day tariffs need to be reviewed to be more renewables responsive and fuel surcharge levy needs to be frequently levied.

Regular levy of fuel surcharge: In addition to inflation-linked tariffs, the DISCOMs should calculate and levy fuel surcharge in line with SERC regulations on a monthly or quarterly basis, as specified. Almost all state regulators have notified fuel surcharge regulations, but it is not being regularly levied on consumers.

Re-examining ToD tariffs in the light of increased renewable energy supply: SERCs and state governments, in consultation with DISCOMs, should introduce ToD tariffs with adequate daytime incentives for power consumption and night/morning/evening peak penalties along with seasonal variation in penalties. In addition, the ToD tariff regime should be extended to all consumers with demand greater than 10 kW or those having appropriate metering infrastructure, capable for ToD slot-wise energy accounting, within a two-year period.

Cost-reflective services for open access, captive and net metering consumers: DISCOMs provide several services such as banking and standby to consumers using captive power and net-metering arrangements at non-compensatory rates. In the case of open access, at least the recovery of additional surcharge and cross-subsidy surcharge compensates DISCOMs. Captive and net metering consumers are exempt from these charges. Ideally, to reduce the burden of power procurement on DISCOMs and their consumers, DISCOMs should ensure that their services, especially standby and banking, are compensated for appropriately.

9.3.3 Strengthening APTEL as an institution for swift resolution of disputes

As detailed in Section 4.2, several crucial tariff-related matters lie pending before APTEL for prolonged periods, and these delays contribute to the escalating interest costs and growing financial liabilities of the sector.

To address the increasing complexity of the power sector and the growing caseload before APTEL, it is crucial to expand APTEL's capacity from the current 4 members and 1 Chairperson to 11 members and 1 Chairperson. Additionally, regional benches should be operationalised within a one-year time frame. The central government should also commission a comprehensive study to assess how APTEL's processes—particularly case management, staffing for benches and use of technology-enabled solutions—can be enhanced to improve efficiency and order quality and reduce case pendency. Based on the study's recommendations, guidelines for improving APTEL's processes should be notified.

Similarly, a review of regulatory commission processes and functioning is essential, which could be undertaken by an independent committee constituted by APTEL with representation from DISCOMs, Forum of Regulators, the MoP, academic institutions and sector experts.

9.4 Structural measures towards larger reforms to increase competition

Renewable energy with storage can provide supply to meet almost all of the consumers requirement at less than ₹6 per unit. This cost is less than the energy charge paid by industrial consumers for electricity in 21 of 28 states.

With renewable energy and storage tariffs proving more competitive than C&I tariffs, enterprises are increasingly finding investment in renewable-energy-based captive capacity an attractive option. With concessional services such as banking and standby to ensure reliability, energy cost savings from switching to such alternatives range from 10% to 40% across different states. These options not only enhance cost competitiveness but also help meet compliance requirements under CBAM and similar carbon border policies, as well as satisfying investor ESG mandates.

Under the Green Open Access Rules and subsequent SERC regulations adopted across 27 states, consumers with demand exceeding 100 kW—representing approximately 30–35% of national demand—are eligible to directly procure green energy from sources other than DISCOMs. This demand segment also presents new opportunities for private investment, particularly as generation investments shift from the large up-front commitments required for conventional technologies such as coal and hydropower to more flexible, modular and scalable deployments characteristic of solar power.

However, DISCOMs operating under regulatory tariff mechanisms rather than market-based pricing and using administrative rather than techno-economic approaches to power procurement would perhaps struggle to meet this growing demand from C&I enterprises cost-competitively. DISCOMs must procure substantial power capacity to serve uncertain demand as customers cherry-pick between regulated and market options. At the same time, regulators will likely price these reliability services at concessional rates,[93] even though such services should ideally be determined by market mechanisms. In all likelihood, this will affect the future viability of DISCOMs. Further, to retain consumers in the short term, DISCOMs may resort to creating administrative and procedural barriers to limit access to the power market, disproportionately impacting India's MSME segment and smaller enterprises, for whom the transaction cost of market access could be prohibitive.

Without calibrated, medium-term structural reforms to redefine DISCOM roles, pricing mechanisms and service provision models, significant losses and stranded assets may accumulate. As discussed in Chapter 7 even aggressive measures to increase tariffs and reduce operational costs may prove insufficient to offset unplanned revenue losses from customer migration to alternative sources. This could trigger a cycle of financial decline that will ultimately undermine the power sector's capacity to reliably serve India's expanding industrial base and ambitions for economic growth. This should also be seen in the context of the analysis in Section 7.1, which points to the limited and shrinking contribution of cross-subsidy revenue from industrial consumers.

Further, market-based procurement from multiple suppliers is possible for HT consumers, for whom investments in advanced metering infrastructure have been made over decades and practices of wheeling, energy accounting, scheduling and deviation settlement are well

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[93] In addition, revenue from cross-subsidy from these consumers is also decreasing as a result of regulatory efforts to align tariffs with the cost of supply over the past decade. In fact, industrial consumers in 19 states on average pay less than 120% of the actual cost of supply. In 10 of these 19 states, they pay at average cost or below.

established. Therefore, for these consumers, it would be in the interests of both DISCOMs and the sector to **move away from regulated, cost-plus tariff determination to a market-based tariff determination approach.** For these consumers, the DISCOM would function more as a NETCOM providing only network services than as a DISCOM providing network and supply services.

9.4.1 The proposal

For HT consumers, the proposed structural reform measure is to move away from power supply provision by a regulated monopoly service provider (i.e., the DISCOM) towards multiple competitive supply arrangements (i.e., the market).

To enable this, DISCOMs should be freed of any obligation to supply power to HT consumers at SERC-determined regulated tariffs within a five-year period. If required, power can be supplied by DISCOMs at mutually agreed/market rates.[94] HT consumers could procure from any DISCOM in the country, traders, power exchanges or generators. National and state-level bulk suppliers could also be introduced to aggregate demand through standardised contracts and supply bulk power at competitive rates. However, the charges for wheeling power or for DISCOMs supply services as "provider of last resort" should ideally be at SERC-determined tariffs. DISCOM service as provider of last resort should be at a premium rate of around 2 to 3 times the ACOS.

To enable investment in HT networks in order to support the reliability requirements of HT consumers, private participation in HT network investments through competitive bidding and O&M franchisee models could also be explored.

In addition, open access processes need to be simplified (especially those related to application procedures, consent provision, etc.), additional charges on open access such as cross-subsidy surcharge and additional surcharge could be discontinued and several of the eligibility requirements for captive power could be removed.

This fundamental switch to market-based procurement would represent a major change in the DISCOM business model and will result in revenue loss without commensurate cost reduction in the short term. However, in the long term, it would help streamline investments, reduce power procurement requirements and cost, and expand opportunities for market-driven revenue generation.

To address the increased financial stress in the transition period, a non-budgetary support mechanism could be established by which all migrating HT consumers pay ₹2.5 per unit to the DISCOMs for a limited period of five years. This mechanism could provide transitional financial support of about ₹53,000 crore each year for five years without any fiscal impact on state governments.[95] Consumers would also benefit because this charge would only be applicable for a five-year period and no other similar charge would be applicable after this period, providing them predictability and clarity for long-term investments.

With their power procurement risks significantly mitigated, the DISCOMs' role would thus gradually transition to primarily serving as a network service provider. Over time, they would focus on serving small consumers who remain within the regulated framework. Of these,

[94] These rates could be subject to regulatory measures to ring-fence the DISCOMs' regulated business from the unregulated transactions with HT consumers, for example, by fixing a floor price for DISCOM trades and SERC monitoring of non-regulated transactions.

[95] Duties on captive and other charges such as point of connection charges could be subsumed under this charge.

agricultural consumers will be solarised. Therefore, the focus for power procurement would be limited to small residential and small enterprise consumers, who can also be gradually given the option to use market-based solutions as the network and metering infrastructure improves.

Such an approach would prevent the build-up of future losses for DISCOMs, enable market-based, competitive service provision to India's enterprises and renew focus and interest in network investments, grid operations as well as reliable supply for small and rural consumers.

9.4.2 Enabling the framework to operationalise this proposal

For states opting for 'deregulation of HT consumers' within a five-year period, additional central government support of up to ₹1/unit for incremental open access sales from FY26 for three years could be provided. Assuming 45% of HT consumers use open access in the three-year period, with an increase of 15% each year, the additional central government support provided across all states to operationalise enabling frameworks for HT deregulation would be ₹7,900 crore per year for three years. This could be enhanced, depending on the states' performance and requirements, to meet the strategic objective of moving a significant part of the power sector to market-based pricing and a competitive structure.

In addition, as described earlier, transition finance could be raised through, say, a 'supply obligation charge' of ₹2.5/unit **from consumers.** This would translate to up to ₹53,000 crore/year for five years of support to DISCOMs without budgetary outgo. Such a charge should only be levied in states where state governments enable HT deregulation for the first five years.

To summarise, the financial impact of the proposed approach involves a tranche-wise takeover of losses by state governments through 20-year bonds, requiring an all-India state government budgetary commitment ranging from ₹15,000 crore in Year 1 to ₹92,000 crore annually from Year 5 to Year 20. Critically, DISCOMs will only be eligible for each successive tranche when they meet the annual milestones outlined in their mandatory five-year plans, co-developed with the state government.

To incentivize participation from state governments and ensure implementation success, the central government could provide capital reimbursement of up to ₹14,900 crore for essential network investments, interest subvention of ₹5,500 crore for five years on state government bonds, and ₹21,000 crore in financial assistance for agricultural feeder solarization. All central support remains conditional on states meeting their annual reform commitments. For states adopting HT deregulation, additional targeted support from the central government could be available: ₹1 per unit for incremental open access sales (up to ₹7,900 crore annually for three years). This shall be supplemented by ₹53,000 crore in transitional financing through regulatory charges from migrating consumers for a five year period that require no budgetary outlay.

The potential benefits of the proposed approach are substantial and wide-ranging. Agricultural solarization alone could generate annual savings of ₹77,000 to ₹90,000 crore, while inflation-linked tariffs would reduce accumulated losses by ₹60,000 crore annually and deliver interest cost savings of ₹18,000 crore per year. These benefits substantially exceed the reform costs, creating a pathway to financial sustainability rather than increasing dependence of government support.

The proposed HT deregulation represents a fundamental structural transformation—shifting a significant consumer segment from regulated cost-plus models to competitive market operations. This transition would drive private investment in both supply and network infrastructure while catalyzing robust electricity market development. Most importantly, it would effectively prevent the build-up of future losses by aligning DISCOM operations with market realities.

Without comprehensive reform, the underlying drivers of loss accumulation could remain unaddressed, locking the sector in endless cycles of crisis and bailout. Delay in adoption could make the future financial losses more significant in some states and the solutions to address them more limited. The financial sustainability of India's electricity sector—and by extension, the viability of the country's energy transition and industrial competitiveness—hangs in the balance. This is not merely another restructuring scheme, but a fundamental reimagining of how India's power sector operates. The alternative is a future of intractable crisis that no subsequent intervention can adequately address.

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11 Annexures

Annexure 1: Build-up of losses and liabilities across states since 2001

Table 36 details the share of outstanding dues to central public sector units of the top contributing SEBs to the national aggregate outstanding dues identified for takeover under the Settlement of SEB Dues Scheme.

Table 36: Outstanding dues to CPSUs February 2001

State-wise outstanding dues as % of total dues identified under scheme	
State	%
Bihar	14%
Delhi	13%
Uttar Pradesh	12%
Madhya Pradesh	9%
West Bengal	9%
Gujarat	5%
Haryana	5%
Maharashtra	5%
Total	**74%**

Source: (Planning Commission, 2001)

Under the FRP scheme, short-term liabilities of DISCOMs were identified for takeover across states. Table 37 lists the share of the top contributors to the national aggregate outstanding liabilities identified for takeover.

Table 37: State-wise Outstanding liabilities as a % of total liabilities identified under FRP

Outstanding short-term liabilities in each state as % of total liabilities identified under FRP (as on 31st March 2012)	
State	% of total
Rajasthan	21%
Uttar Pradesh	14%
Tamil Nadu	10%
Haryana	8%
Punjab	6%
Andhra Pradesh	3%
Madhya Pradesh	1%

Source: (MoP, 2012)

Annexure 2: Trends in accumulated losses from FY16 to FY24

Table 38 shows the outstanding accumulated losses at the end of each financial year since the launch of UDAY along with the CAGR (nominal terms) for the parameter for the period.

Table 38: Year on year change in accumulated losses of state-owned DISCOMs

State	FY16	FY17	FY18	FY19	FY20	FY21	FY22	FY23	FY24	CAGR
Kerala	2,185	7,408	9,777	11,239	12,104	18,970	24,266	29,335	35,978	42%
Jharkhand	1,897	3,824	4,521	5,127	6,261	9,183	11,556	15,175	18,469	33%
Karnataka	3,027	4,186	4,725	3,794	5,645	9,821	14,413	17,559	26,109	31%
Manipur	62	77	85	116	131	146	157	286	295	22%
Bihar	4,256	6,603	9,244	12,258	14,673	17,160	19,537	19,322	18,503	20%
Telangana	16,520	22,577	28,209	36,231	42,293	48,982	49,816	60,922	67,276	19%
Meghalaya	1,153	1,492	1,779	1,969	2,413	2,475	2,636	4,104	4,634	19%
Tripura	388	406	441	333	391	382	514	804	1,171	15%
Punjab	3,220	6,056	6,963	7,001	8,159	6,713	5,644	10,420	9,620	15%
Uttarakhand	2,051	2,340	2,569	3,122	3,699	3,851	3,872	5,096	5,435	13%
Tamil Nadu	63,162	67,511	75,272	87,895	99,860	1,38,643	1,51,639	1,62,507	1,66,944	13%
Andhra Pradesh	14,484	16,819	16,822	29,147	29,143	28,707	31,195	29,218	29,210	9%
Madhya Pradesh	35,664	37,125	43,733	51,061	52,981	56,880	61,010	64,843	69,301	9%
Himachal Pradesh	2,000	2,044	1,535	1,532	1,521	1,706	1,810	3,246	3,754	8%
Chhattisgarh	5,575	5,996	6,275	6,318	7,290	7,710	8,924	10,057	10,016	8%
Maharashtra	26,246	27,380	26,887	25,791	23,428	26,251	26,070	31,275	36,226	4%
Uttar Pradesh	67,776	71,097	75,829	81,342	85,069	70,661	78,004	91,632	89,662	4%
Rajasthan	92,652	94,633	92,460	89,854	86,868	89,084	89,556	92,070	91,565	0%
Haryana	29,064	30,030	29,590	29,309	28,978	28,341	28,404	28,165	28,001	0%
Assam	3,089	3,123	2,975	1,913	959	1,229	893	1,699	1,324	-10%
West Bengal	126	111	87	43	-3	-34	-83	-119	-158	
Total	**3,78,411**	**4,10,126**	**4,44,104**	**4,91,057**	**5,11,644**	**5,66,425**	**6,09,035**	**6,76,681**	**7,08,170**	**8.15%**

Source: PFC Report of the performance of power utilities, various years

Annexure 3: Source-wise power procurement cost across 17 states

Details of source-wise power procurement across 17 states are compiled from tariff orders and petitions to provide an overview of source-wise power procurement mix as well as power purchase costs. This is crucial given that power purchase accounts for 70% or more of DISCOM expenses and even with operational improvements towards increasing efficiency, the nature and cost of contracted capacity will play a disproportionate role in determining cost-efficiency of DISCOMs.

Table 39: Source-wise power purchase cost: Uttar Pradesh, Bihar, Chhattisgarh

Source	Uttar Pradesh		Bihar		Chhattisgarh	
	% share	₹/unit	% share	₹/unit	% share	₹/unit
Coal	80%	4.59	86%	4.74	81%	3.71
Gas	0%	0.00	0%	0.00	0%	0.00
Nuclear	1%	3.41	0%	0.00	1%	3.83
Large Hydro	9%	4.30	5%	3.43	10%	2.95
Renewables	7%	4.14	9%	3.10	8%	5.95
Market	2%	7.69	1%	12.16	0%	0.00
Total	**100%**	**4.61**	**100%**	**4.60**	**100%**	**3.88**

Note: Data for Uttar Pradesh is for FY23
Source: Tariff orders and petitions of DISCOMs

Uttar Pradesh, Bihar, and Chhattisgarh have high dependence on coal-based power generation, with coal constituting over 80% of their electricity procurement mix. This heavy reliance on a single fuel source exposes these states' DISCOMs to significant risks from coal price volatility and supply disruptions. Despite comparable coal dependency levels, procurement costs vary substantially across these states. Chhattisgarh achieves significantly lower coal-based power costs at ₹3.71 per unit compared to ₹4.59 per unit in Uttar Pradesh and ₹4.74 per unit in Bihar. This cost advantage stems from Chhattisgarh's higher proportion of pit-head power stations, which substantially reduce transportation expenses that typically constitute a major component of coal power costs. Market-based power purchases remain minimal across all three states, with Uttar Pradesh sourcing only 2% and Bihar 1% from short-term markets, while Chhattisgarh has no short-term market exposure. However, when these states do purchase from markets, costs are substantially higher—reaching ₹7.69 per unit in Uttar Pradesh and ₹12.16 per unit in Bihar. Renewable energy procurement (excluding large hydro) remains inadequate, with all three states maintaining renewable shares below 10% of their total procurement mix.

Table 40: Power purchase cost: Gujarat, Maharashtra, Punjab, Rajasthan

Source	Gujarat		Maharashtra		Punjab		Rajasthan	
	% share	₹/unit	% share	₹/unit	% share	₹ /unit	% share	₹/unit
Coal	74%	4.87	76%	4.93	70%	4.43	72%	4.73
Gas	2%	11.95	1%	8.71	0%	0.00	1%	6.13
Nuclear	3%	3.78	3%	3.75	2%	3.47	2%	3.47
Large Hydro	1%	1.57	3%	2.24	9%	3.81	7%	2.43
Renewables	13%	3.69	12%	4.40	9%	4.42	11%	4.83
Market	6%	6.21	6%	4.78	10%	5.23	7%	5.77
Total	**100%**	**4.86**	**100%**	**4.79**	**100%**	**4.49**	**100%**	**4.64**

Source: Tariff orders and petitions of DISCOMs

Gujarat, Maharashtra, Punjab, and Rajasthan demonstrate high coal dependency, with coal-based power plants meeting 70% to 76% of their electricity procurement requirements. Coal procurement costs remain relatively similar across these states, ranging from ₹4.43 per unit in Punjab to ₹4.93 per unit in Maharashtra. Among these states, Punjab is unique with its substantial reliance on large hydro resources (9% of procurement mix at ₹3.81 per unit) and significant market-based purchases (10% at ₹5.23 per unit), which increases its overall procurement costs. Renewable energy purchase varies considerably: Gujarat and Rajasthan achieve 13% and 11% renewable shares respectively, while Maharashtra maintains 12%. Punjab lags significantly in renewable adoption with only 9% of procurement from renewable sources (excluding large hydro).

Table 41: Source-wise power purchase cost: Madhya Pradesh and Odisha

Source	Madhya Pradesh		Odisha	
	% share	₹/unit	% share	₹/unit
Coal	77%	3.92	73%	3.33
Gas	0%	0.00	0%	0.00
Nuclear	3%	3.07	0%	0.00
Large Hydro	11%	2.12	17%	1.63
Renewables	9%	4.55	8%	3.58
Market	0%	4.49	2%	5.29
Total	**100%**	**3.76**	**100%**	**3.10**

Source: Tariff orders and petitions of DISCOMs

Madhya Pradesh and Odisha have contracted coal-based capacity to meet about three-quarters of their electricity supply. Despite this heavy coal dependency, both states achieve substantially lower power costs due to the proximity of contracted coal plants to coal mines. Both states benefit from substantial Large Hydro resources, with Madhya Pradesh sourcing 11% of its power from hydro at ₹2.12 per unit and Odisha procuring 17% at ₹1.63 per unit. Renewable energy purchase remains modest in both states, accounting for 9% of procurement in Madhya Pradesh and 8% in Odisha.

Table 42: Power purchase cost: Haryana, Andhra Pradesh, Tamil Nadu, Telangana

Source	Haryana		Andhra Pradesh		Tamil Nadu		Telangana	
	% share	₹/unit	% share	₹/unit	% share	₹/unit	% share	₹/unit
Coal	63%	4.49	64%	5.19	65%	5.30	67%	5.10
Gas	0%	22.00	0%	0.00	2%	8.27	0%	0.00
Nuclear	1%	3.46	1%	3.74	11%	4.27	2%	3.58
Large Hydro	14%	2.59	2%	3.30	5%	3.18	1%	21.00
Renewables	10%	3.42	19%	4.48	11%	4.14	12%	4.80
Market	12%	7.01	13%	8.01	6%	6.38	18%	5.26
Total	**100%**	**4.47**	**100%**	**5.37**	**100%**	**5.07**	**100%**	**5.27**

Note: Data for Telangana and Tamil Nadu are projections rather than actuals
Source: Tariff orders and petitions of DISCOMs

Haryana, Andhra Pradesh, Tamil Nadu, and Telangana demonstrate similar and relatively lower coal dependency levels, with coal-based power constituting 63% to 67% of their electricity procurement. However, coal procurement costs are substantially higher across these states, ranging from ₹4.49 per unit in Haryana to ₹5.30 per unit in Tamil Nadu. Haryana benefits from significant large hydro capacity (14% of total procurement at ₹2.59 per unit), which helps mitigate overall procurement costs and contributes to its relatively lower total cost of ₹4.47 per unit. All four states exhibit considerable dependence on short-term market purchases, with market procurement ranging from 10% in Tamil Nadu (as reported in actuals as compared to commission projections) to 18% in Telangana. Renewable energy purchase is relatively high in these states ranging from 10% in Haryana to 19% in Andhra Pradesh.

Annexure 4: Delays and Slippages in case of cost-plus projects in 7 states

Table 43: Average delay in commissioning of cost plus capacity

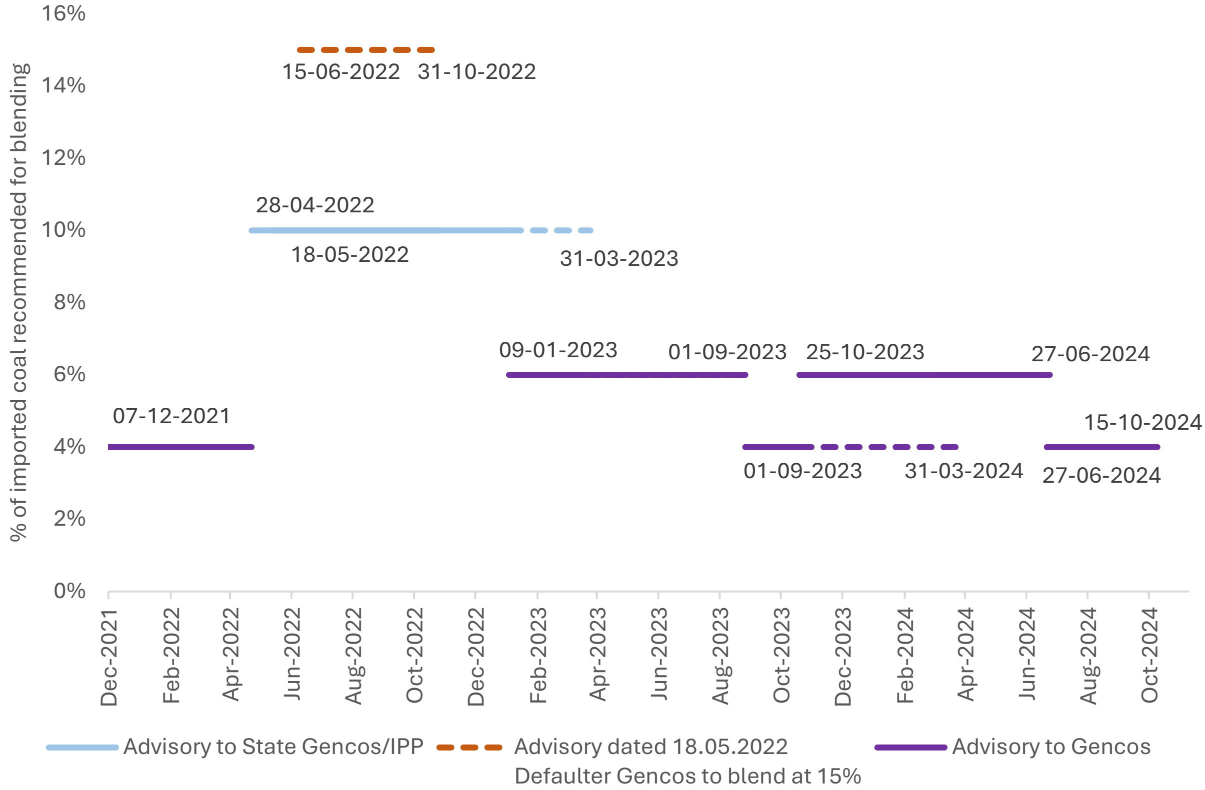
Average Delay (in months) in commissioning of "Cost-Plus" capacity across states			
State	**Central**	**State**	**Private**
Uttar Pradesh	32	42	0
Telangana	24	59	0
Andhra Pradesh	21	87	30
Maharashtra	12	29	0
Madhya Pradesh	16	4	29
Rajasthan	15	30	36
Tamil Nadu	49	0	114

Source: Compiled from regulatory orders and petitions and CEA reports on broad status report of under construction thermal power projects across years.

Data on delays in commissioning of "cost plus" capacity across seven states was tracked. State sector projects experience the most severe delays, ranging from 4 months in Madhya Pradesh to 87 months in Andhra Pradesh. Central sector capacity commissioning faces delays of 4 years to 12 months, with Tamil Nadu experiencing the longest delays at 49 months while Maharashtra achieves relatively shorter delays at 12 months. Privately owned cost-plus capacity demonstrates delays ranging from 9.5 months to 2.4 years, with Tamil Nadu recording the most extensive delays at 114 months and several states reporting no private cost-plus capacity additions. These extensive delays stem from the lack of strict contractual provisions in cost-plus arrangements compared to competitive bidding frameworks. When construction delays are deemed prudent, the associated interest costs during construction are passed through to consumers, such that project developers face limited financial consequences for delays while DISCOMs and ultimately consumers bear the cost burden.

Annexure 5: Time-line of advisories related to imported coal blending

Figure 13: Time line of advisories for coal blending with recommended % of imported coal



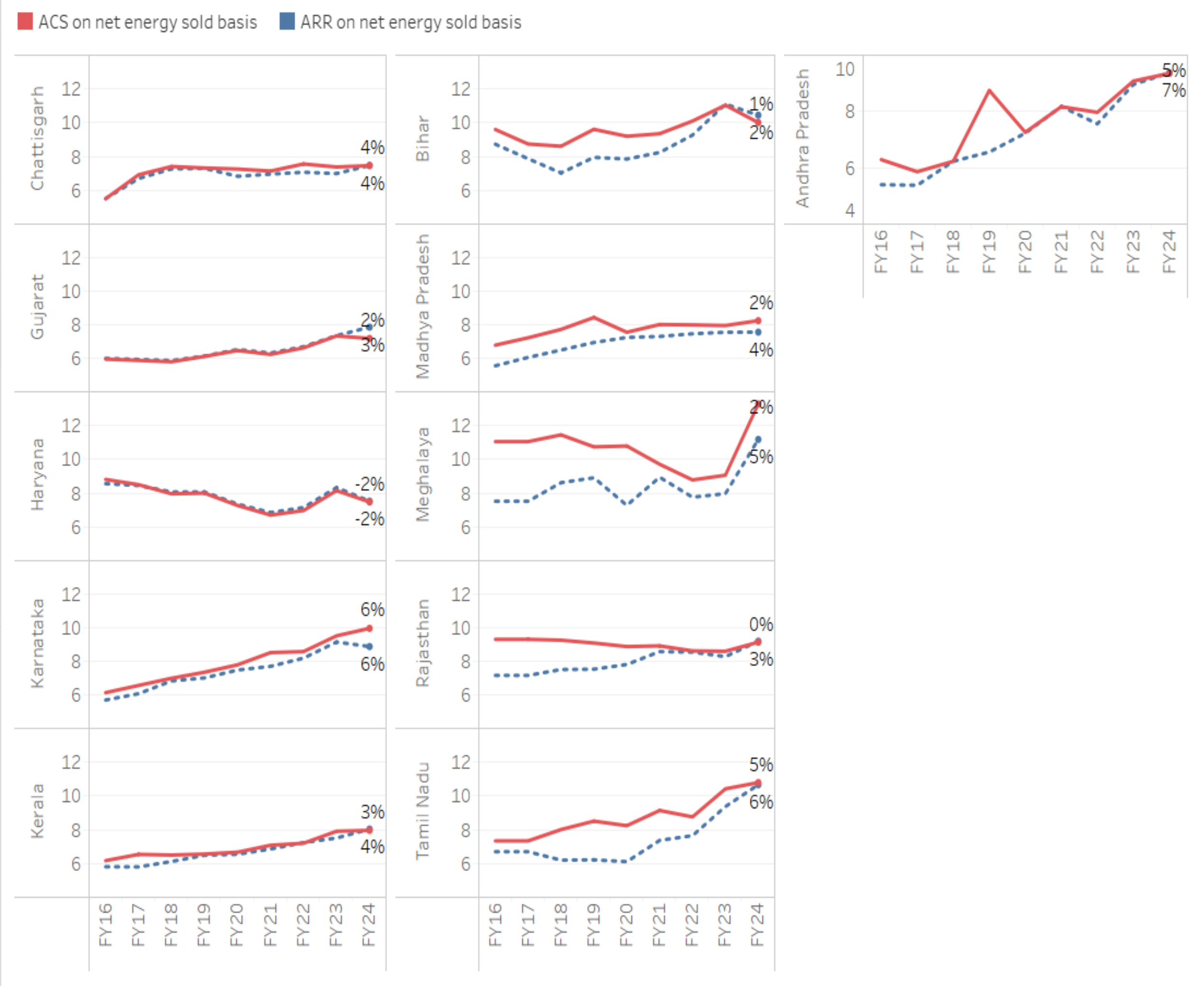
Source: Various advisories issued by the MoP

Annexure 6: Revenue and Cost Trends since UDAY (FY15 to FY24)

Figures 14 and 15 track the year on year changes in average per unit cost and per unit revenue billed for nine years in 22 states. The gap between the cost and revenue trends is indicative of the average per unit revenue gaps in states. This is indicative of disallowance in costs, delayed recovery of prudent cost and lack of adequate tariff increase. Persistent gaps contribute to build-up of accumulated losses in the state.

Figure 14 shows that there hardly any revenue gaps in Chhattisgarh, Gujarat, Haryana, Karnataka and Kerala. This is because of timely tariff revision and relatively slow growth in costs. In Karnataka, the, revenue gap seems to be increasing in FY24. In Bihar, Madhya Pradesh, Meghalaya, Rajasthan, Tamil Nadu and Andhra Pradesh, the revenue gap seems to be narrowing post FY20.

Figure 14: Average cost of supply and Average revenue billed across 11 states for 9 years



Source: Report on the Performance of State Power Utilities by PFC (various years)

Figure 15 details the trends in 11 other states. In Jharkhand, Tripura, Telangana the revenue gap has widened in recent years due to sharp increase in costs without commensurate increase in revenue billed. The state also shows significant volatility in costs especially in Assam, Uttar Pradesh, Punjab, Himachal Pradesh and West Bengal. This volatility is mostly due to coal and gas availability and year on year changes in availability of hydro power.

Figure 15: Average cost of supply and Average revenue billed across 11 states for 9 years

Source: Report on the Performance of State Power Utilities by PFC (various years)

Annexure 7: Change in receivables (days) over time

Receivables change on a year on year basis due to improvements in arrear collection, state government schemes to clear pending dues, major disruptions such as covid-19 etc. To understand changes in receivables across states over time, the average receivables in days was tracked for two time periods The first period was shortly after UDAY between FY17 and FY20 and the second was during the rollout of RDSS between FY21 and FY24. This is shown in Table 44.

Table 44:Change in receivables (days) from FY17 to FY24

States with high receivables which have demonstrated improvement		
State	**FY17 to FY20**	**FY21 to FY24**
Uttar Pradesh	477	445
Manipur	561	418
Meghalaya	266	233
West Bengal	122	107
Karnataka	123	93
Assam	110	83
Odisha	143	42

States where receivables have deteriorated		
State	**FY 17 to FY20**	**FY21 to FY24**
Jharkhand	310	403
Bihar	157	237
Maharashtra	201	228
Telangana	120	190
Madhya Pradesh	145	172
Andhra Pradesh	88	101
Punjab	66	87
Tripura	58	86

States with healthy receivables		
State	**FY 17 to FY20**	**FY21 to FY24**
Tamil Nadu	60	63
Kerala	60	52
Gujarat	36	39
Rajasthan	42	39
Haryana	51	36
Dadra & Nagar Haveli and Daman & Diu	34	28
Uttarakhand	33	27
Himachal Pradesh	34	20
Delhi	15	15

Source: Report on the Performance of State Power Utilities (various years)

Annexure 8: Impact of loss takeover on FD/GSDP

Table 45 shows the annual outgo with the issue of 20 year bonds for DISCOM loss takeover across states as a percentage of the state GSDP. The annual outgo as % of GSDP is shown for both one-time takeover as well as for a tranche-wise takeover over a five year period. This is compared with the fiscal deficit to GSDP ratio for FY24 across states.

Table 45: Comparison of FD/GSDP impact (one-time and tranche-wise loss take-over)

State	FD/GSDP		Impact of loss takeover as % of GSDP					
			Tranches					
	Existing	One-Time	Tranche 1	Tranche 1- 2	Tranche 1- 3	Tranche 1- 4	Tranche 1- 5	Tranche 1-5
	FY24	FY25	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
Unit	%	%	%	%	%	%	%	%
Andhra Pradesh	4.4%	0.21%	0.04%	0.08%	0.11%	0.14%	0.16%	0.14%
Assam	3.7%	0.02%	0.00%	0.01%	0.01%	0.01%	0.01%	0.01%
Bihar	4.1%	0.18%	0.04%	0.07%	0.09%	0.11%	0.13%	0.12%
Chhattisgarh	5.3%	0.18%	0.04%	0.07%	0.10%	0.13%	0.15%	0.14%
Gujarat	1.0%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Haryana	2.9%	0.24%	0.05%	0.09%	0.13%	0.17%	0.20%	0.18%
Himachal Pradesh	5.3%	0.18%	0.04%	0.07%	0.09%	0.11%	0.13%	0.12%
Jharkhand	1.4%	0.40%	0.08%	0.15%	0.20%	0.25%	0.29%	0.25%
Karnataka	2.6%	0.12%	0.02%	0.04%	0.06%	0.08%	0.09%	0.09%
Kerala	3.0%	0.29%	0.06%	0.11%	0.16%	0.19%	0.23%	0.21%
Madhya Pradesh	3.3%	0.52%	0.10%	0.20%	0.29%	0.37%	0.45%	0.41%
Maharashtra	2.2%	0.09%	0.02%	0.03%	0.04%	0.05%	0.06%	0.05%
Manipur	4.3%	0.06%	0.01%	0.02%	0.03%	0.04%	0.05%	0.04%
Meghalaya	5.9%	0.84%	0.17%	0.32%	0.45%	0.57%	0.67%	0.61%
Odisha	1.8%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Punjab	4.3%	0.10%	0.02%	0.04%	0.05%	0.07%	0.08%	0.07%
Rajasthan	4.3%	0.55%	0.11%	0.20%	0.28%	0.34%	0.40%	0.35%
Tamil Nadu	3.4%	0.59%	0.12%	0.22%	0.31%	0.40%	0.47%	0.42%
Telangana	3.4%	0.46%	0.09%	0.17%	0.25%	0.31%	0.37%	0.33%
Tripura	0.8%	0.17%	0.03%	0.07%	0.11%	0.16%	0.20%	0.20%
Uttar Pradesh	3.1%	0.38%	0.08%	0.16%	0.25%	0.35%	0.45%	0.45%
Uttarakhand	2.3%	0.17%	0.03%	0.07%	0.11%	0.16%	0.21%	0.21%
West Bengal	3.3%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.01%

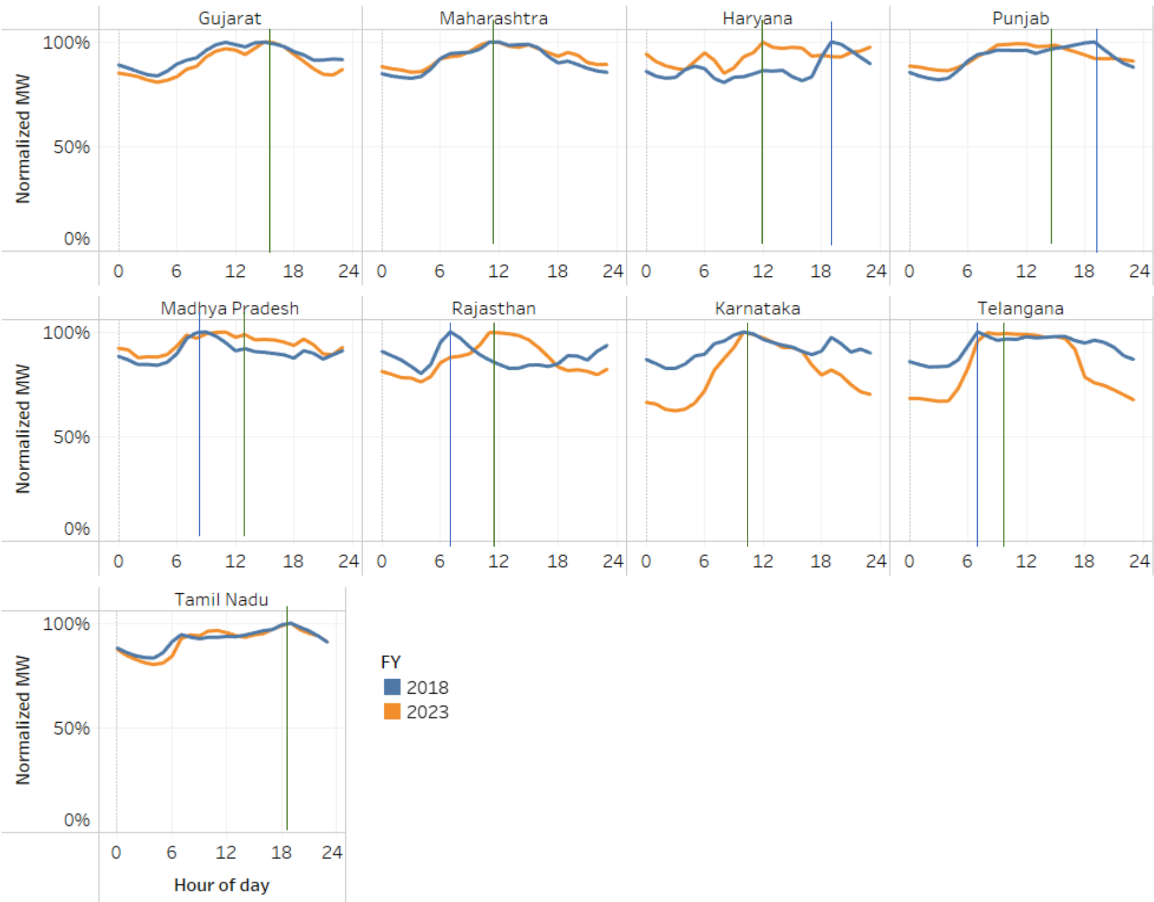
Source: Authors' analysis based on data from (PFC, 2025; RBI, 2024)

Annexure 9: Demand shift to day time in states with High Agriculture shares

Figure 16 presents the aggregate annual average hourly demand for FY18 and FY23 across nine states that collectively account for 90% of India's agricultural electricity demand. The vertical lines indicate peak demand hours for each year, revealing observable shifts in consumption patterns toward daytime hours. This could be attributable to change in agricultural supply hours in these states. Some key observations are below:

- **Punjab and Haryana**: Peak demand shifted from evening hours (18:00-19:00) in FY18 to midday in FY23, indicating successful alignment with solar generation hours.
- **Madhya Pradesh, Rajasthan, and Telangana**: In these states where agriculture constitutes 40% of total demand, average hourly peak demand has moved from early morning hours to daytime periods coinciding with peak solar availability.
- **Gujarat, Maharashtra, and Karnataka**: Peak demand occurred during daytime hours in both years, suggesting these states had already aligned significant agricultural supply with solar hours by FY18.
- **Tamil Nadu**: Peak demand remained in evening hours across both years, indicating limited shift in agricultural demand timing.

Figure 16: Shifting of annual average peak demand between FY18 and FY23



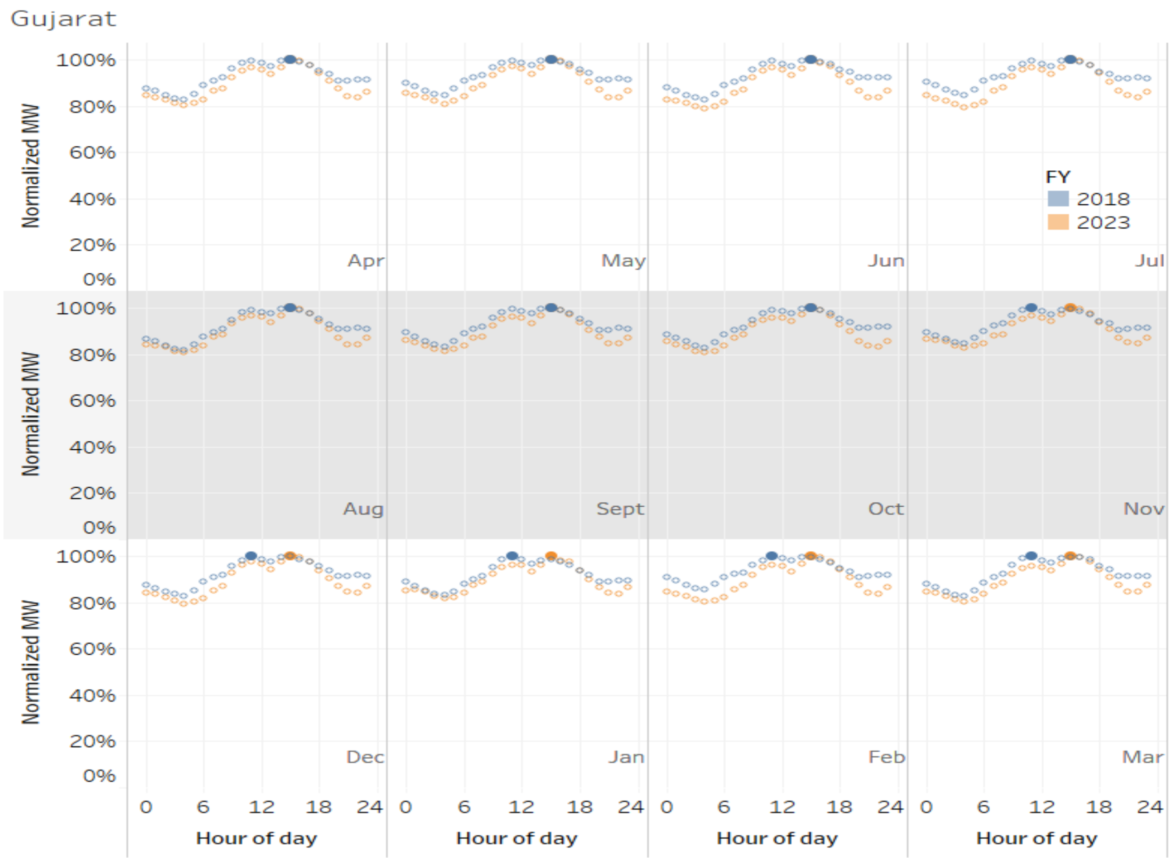
Source: Compiled by authors based on data from Grid India.

While annual average hourly demand provides a broad overview of aggregate demand patterns, it does not definitively establish that observed shifts result from agricultural demand shifting.

To understand trends better, monthly average hourly demand data for FY18 and FY23 was studied to indicate whether demand shifts are more pronounced during agricultural seasons.

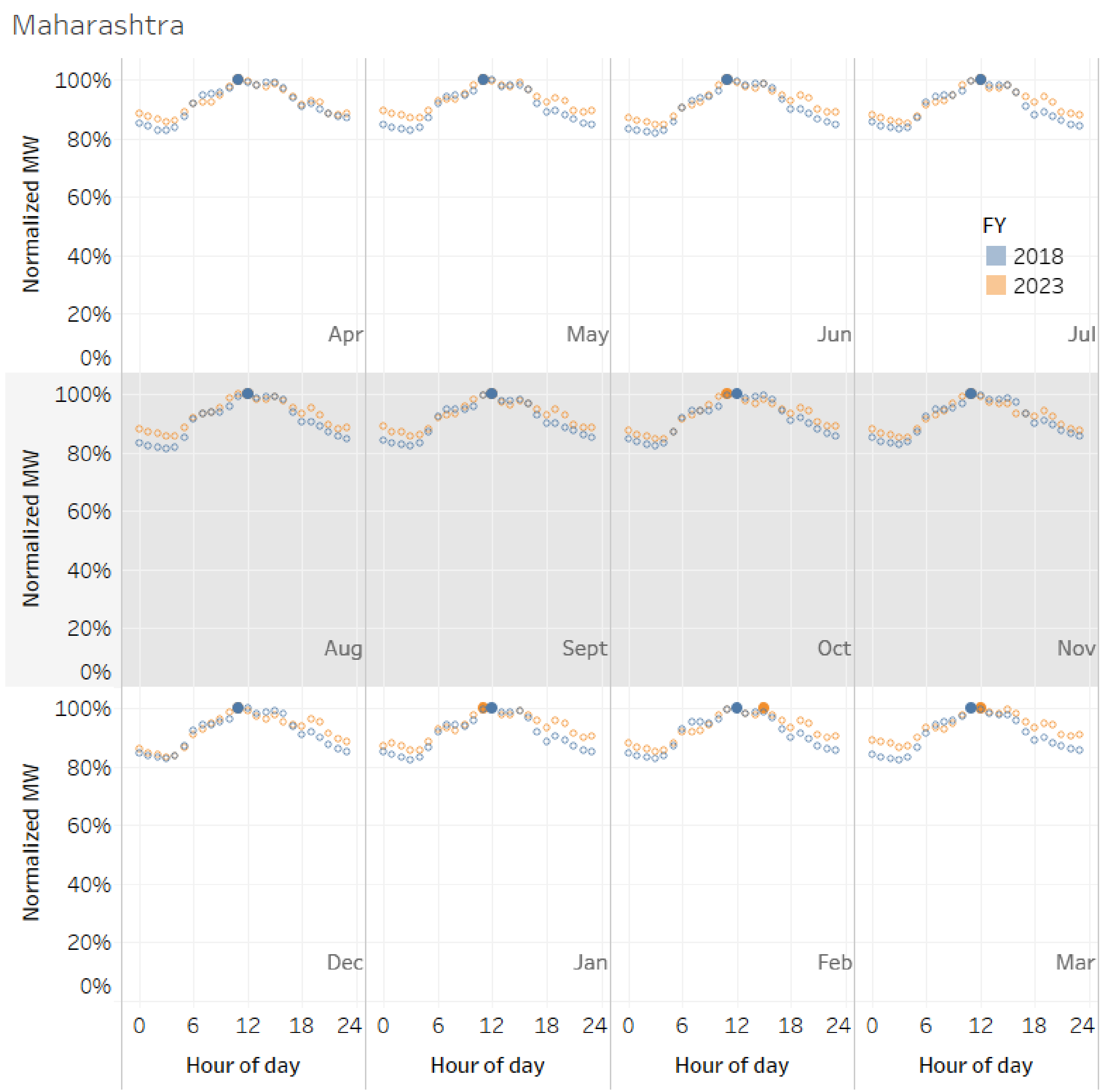
Figures 17 to 22 display monthly average demand patterns for Gujarat, Maharashtra, Haryana, Madhya Pradesh, Punjab, Rajasthan, and Telangana. In these figures, solid coloured dots represent peak demand while hollow dots show hourly average demand levels. The analysis highlights that in Gujarat and Maharashtra, the shift to daytime peak demand in FY23 compared to FY18 is most pronounced between October and March, corresponding to the primary agricultural season. However, in other states, shifting of agricultural demand has perhaps been initiated but may not be substantial. In Rajasthan, demand shifting appears across all months, extending beyond the typical November-March agricultural season. In Punjab and Haryana as well, the daytime demand shifting is evident in most months, with exceptions in March (Haryana) and January (Punjab). In Madhya Pradesh, demand shift patterns are most apparent during specific months—December, January, May, June, and July.

Figure 17: Month-wise hourly average demand in Gujarat (2018 versus 2023)



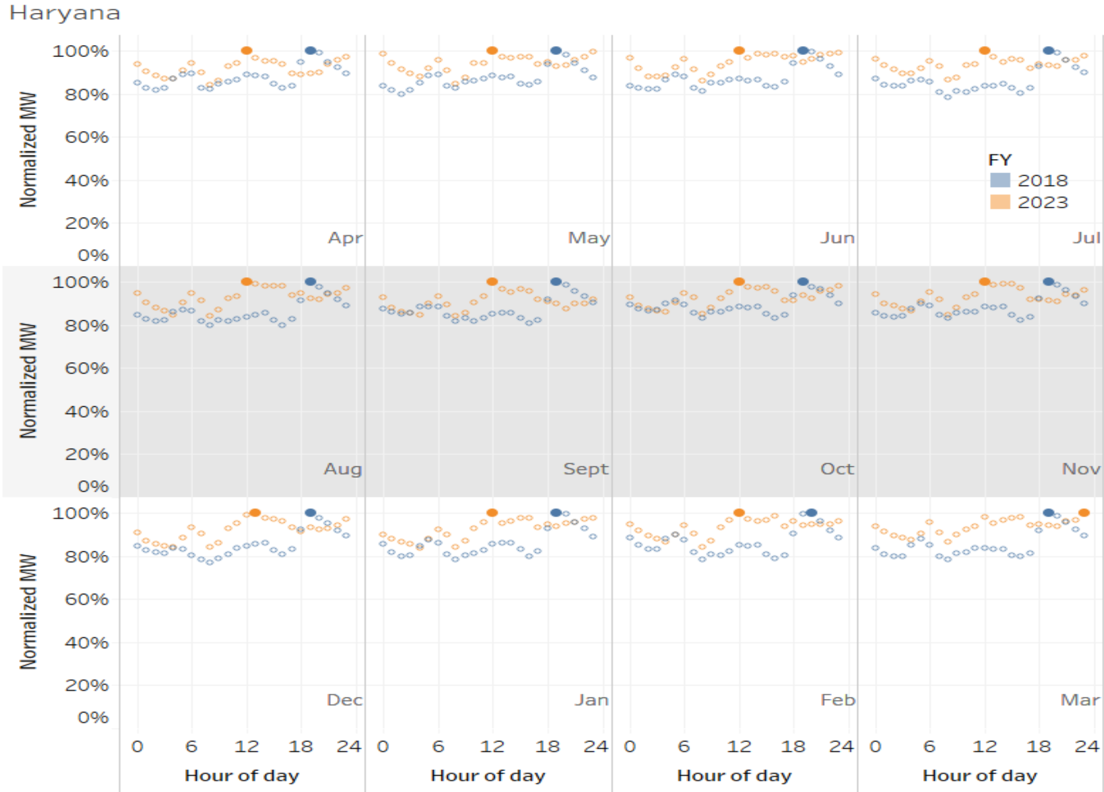
Source: Compiled by authors based on data from Grid India.

Figure 18: Month-wise hourly average demand in Maharashtra (2018 versus 2023)



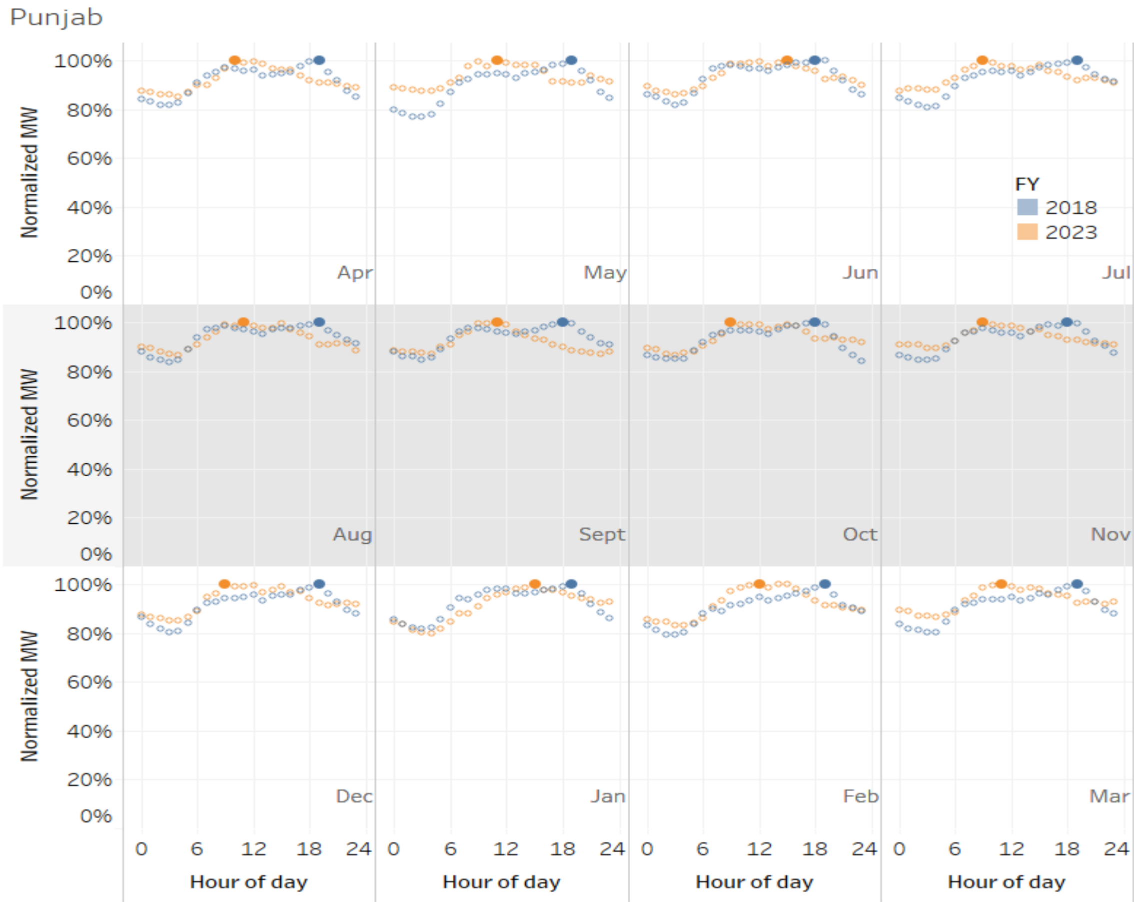
Source: Compiled by authors based on data from Grid India.

Figure 19: Month-wise hourly average demand in Haryana (2018 versus 2023)



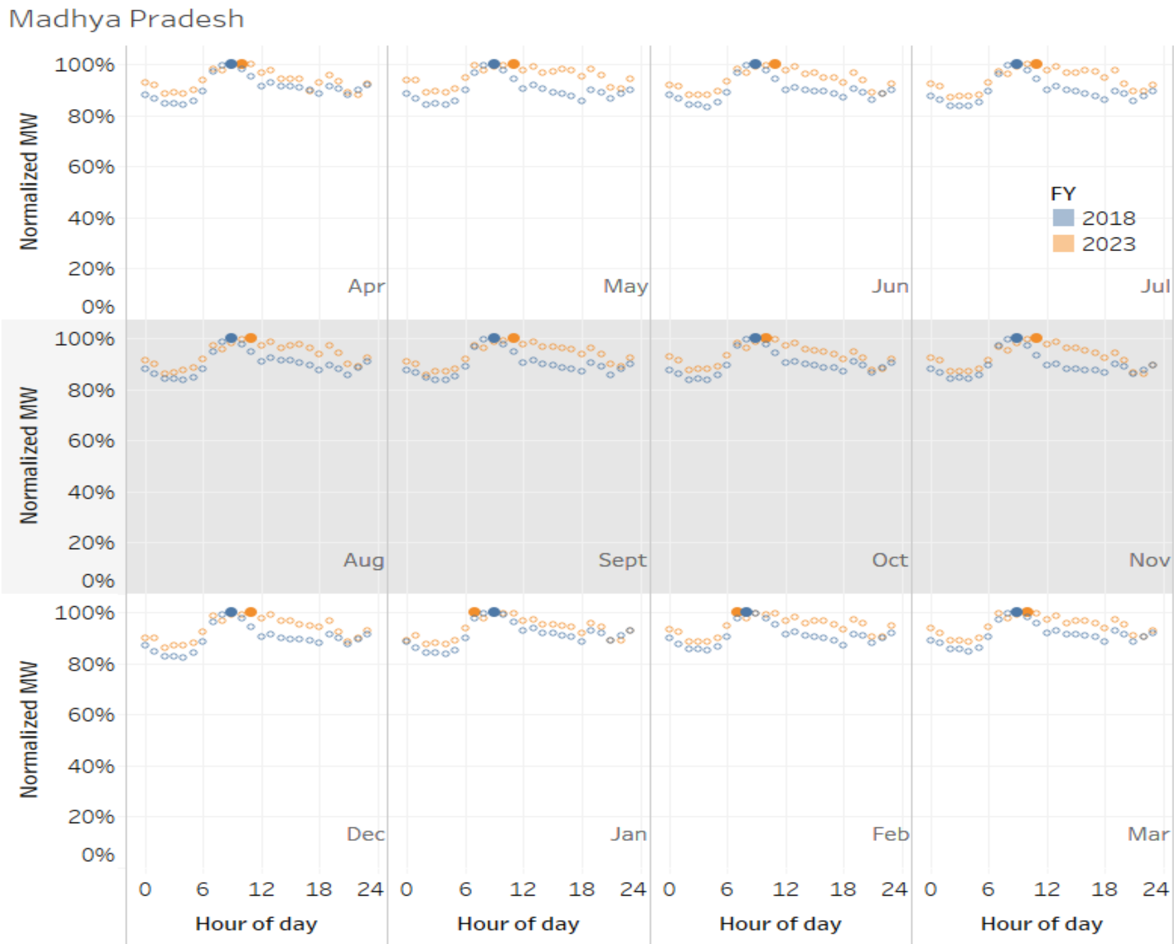
Source: Compiled by authors based on data from Grid India.

Figure 20: Month-wise hourly average demand in Punjab (2018 versus 2023)



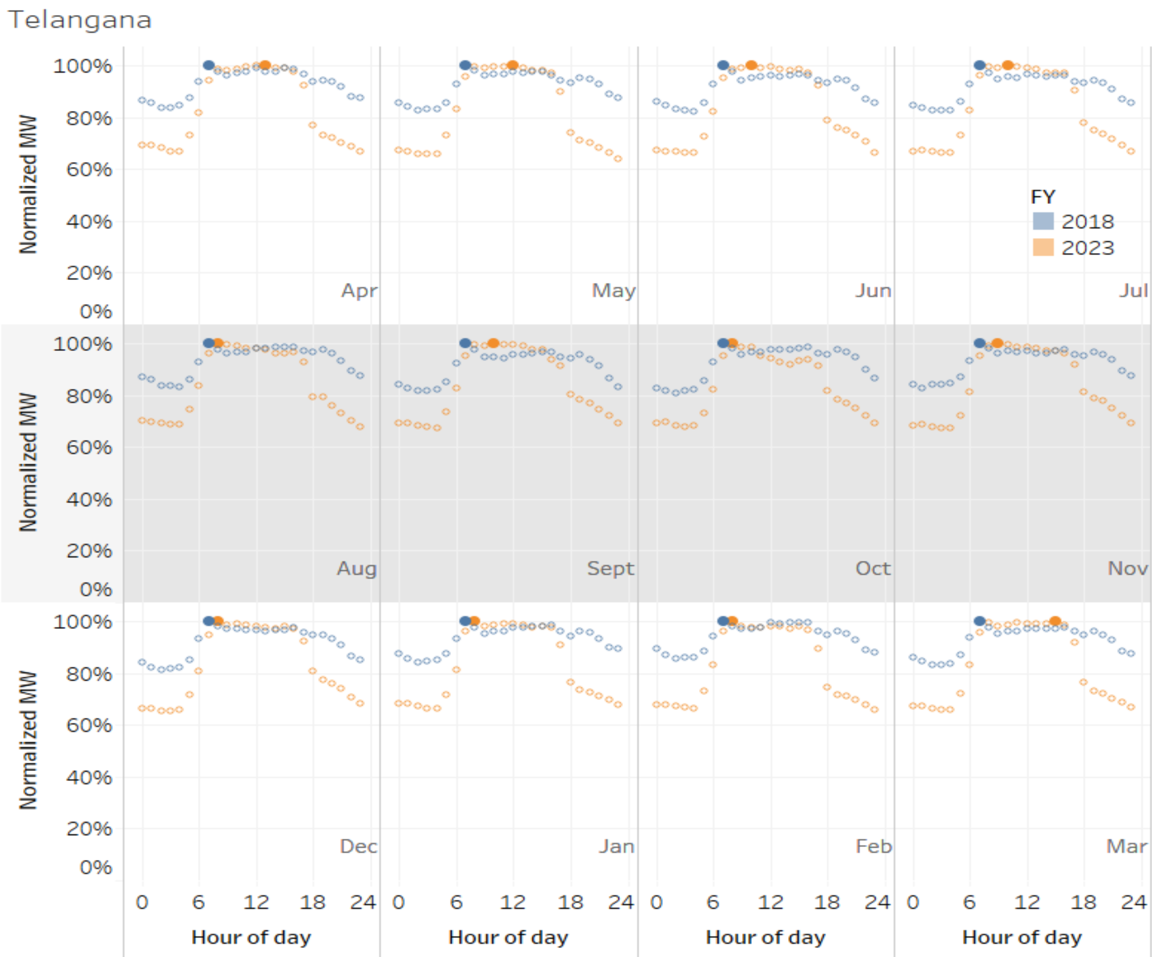
Source: Compiled by authors based on data from Grid India.

Figure 21: Month-wise hourly average demand in Madhya Pradesh (2018 versus 2023)



Source: Compiled by authors based on data from Grid India.

Figure 22: Month-wise hourly average demand in Telangana (2018 versus 2023)



Source: Compiled by authors based on data from Grid India.

Annexure 10: Status of implementation of Time of Day Tariffs

Figure 23 captures the applicable hourly time-of-day tariffs for HT Industrial consumers. The hourly rebate (shown as a percentage of the energy charge component of the tariff) is highlighted in blue, and the surcharge is denoted in yellow. The areas shown in white are periods where neither rebate nor surcharge apply, and the normal energy charge—noted in the right-hand corner—is charged. Figure 24 provides similar data but also shows seasonal variation in ToD tariffs where applicable. Together, the figures cover the status of ToD implementation in 24 of the 36 states that levy such tariffs[96].

The figures show the following patterns:

- Solar Hour Rebates- Only Arunachal Pradesh, Bihar, Chhattisgarh and Madhya Pradesh offer substantial rebates (20%) during solar hours. Rajasthan provides rebates but restricts them to 10% for four hours, while Andhra Pradesh offers 12% for five hours. Odisha provides only a minimal 2% rebate.
- Evening Peak Surcharges- Nearly all states impose significant surcharges during evening peak periods, typically restricted to 6 PM-10 PM. Punjab and Madhya Pradesh do not impose evening peak penalties in certain seasons. In most states, the surcharge varies from 15% to 20% of energy charges.
- Early Morning Pricing: Most significantly, 18 states, which do not provide solar hour rebates, classify the early morning period (12 AM-6 AM) as off-peak. This classification is misaligned with current and future cost realities, as non-solar power costs rise and consumers who rely on self-consumption solar during the day will increasingly depend on DISCOM supply during these hours.
- Seasonal tariffs: Seven states incorporate seasonal variation in their tariffs. In Andhra Pradesh, this involves changes in peak surcharges, while in Himachal Pradesh, it affects off-peak rebates. West Bengal implements marginal tariff adjustments, whereas Uttar Pradesh, Uttarakhand, Punjab, and Madhya Pradesh modify both rates and time slots seasonally.
- Scope for increasing surcharge and rebates: The current rebates and surcharges, which average around 15%, could be more substantial to better reflect cost variations. Kerala demonstrates the potential for more aggressive pricing, levying the highest surcharge at 50% while also providing among the highest rebates at 25%. This is also reflective of their substantial rise in residential demand in evening hours. There has been an increasing recognition of this trend with Maharashtra, Madhya Pradesh shifting the rebates from early morning to solar hours in FY26 and Gujarat removing the early morning rebates in FY24

[96] Only states with mandatory ToD are represented as per tariff order applicable for FY25. Tariff represented for HT Industrial consumer connected at 11kv or above, contracted load 1000 kVA or above and, 70% load factor.

Figure 23: Time of Day tariffs mandated for HT Industry consumers for FY25

ToD for HT Industry Category FY25

State	12 AM	1 AM	2 AM	3 AM	4 AM	5 AM	6 AM	7 AM	8 AM	9 AM	10 AM	11 AM	12 PM	1 PM	2 PM	3 PM	4 PM	5 PM	6 PM	7 PM	8 PM	9 PM	10 PM	11 PM	Energy Charge (Rs./ Unit)
Arunachal Prad..									-20%	-20%	-20%	-20%	-20%	-20%	-20%	-20%		20%	20%	20%	20%				3.85
Assam	-24%	-24%	-24%	-24%	-24%	-24%												24%	24%	24%	24%	24%	-24%	-24%	8.34
Bihar										-20%	-20%	-20%	-20%	-20%	-20%	-20%	-20%	20%	20%	20%	20%	20%	20%		7.98
Chandigarh	-10%	-10%	-10%	-10%	-10%	-10%													20%	20%	20%	20%	-10%	-10%	4.35
Chattisgarh										-20%	-20%	-20%	-20%	-20%	-20%	-20%	-20%	20%	20%	20%	20%	20%	20%		7.35
Delhi	20%	20%			-20%	-20%	-20%	-20%	-20%	-20%	-20%				20%	20%	20%	20%					20%	20%	7.75
Goa	-20%	-20%	-20%	-20%	-20%	-20%	-20%												30%	30%	30%	30%	30%	-20%	5.10
Gujarat								20%	20%	20%	20%								20%	20%	20%	20%			4.20
Jammu & Kash..	-10%	-10%	-10%	-10%	-10%		10%	10%									10%	10%	10%	10%				-10%	4.95
Karnataka	-14%	-14%	-14%	-14%	-14%	-14%	14%	14%	14%										14%	14%	14%	14%	-14%	-14%	6.90
Kerala	-25%	-25%	-25%	-25%	-25%	-25%													50%	50%	50%	50%	-25%	-25%	6.20
Ladakh	-10%	-10%	-10%	-10%	-10%		20%	20%											20%	20%	20%	20%		-10%	3.80
Maharashtra	-18%	-18%	-18%	-18%	-18%	-18%				10%	10%	10%							13%	13%	13%	13%	-18%	-18%	8.36
Meghalaya	-15%	-15%	-15%	-15%	-15%	-15%												20%	20%	20%	20%	20%	20%	-15%	7.30
Odisha									-2%	-2%	-2%	-2%	-2%	-2%	-2%	-2%			4%	4%	4%	4%	4%	4%	4.75
Pudducherry	-10%	-10%	-10%	-10%	-10%	-10%													20%	20%	20%	20%	-10%	-10%	6.00
Rajasthan							5%	5%					-10%	-10%	-10%	-10%			10%	10%	10%	10%			6.30
Tamil Nadu	-5%	-5%	-5%	-5%	-5%		25%	25%	25%	25%									25%	25%	25%	25%	-5%	-5%	7.25
Telangana	-20%	-20%	-20%	-20%	-20%	-20%	13%	13%	13%	13%									13%	13%	13%	13%	-20%	-20%	7.65

Incentive / Penalty(%)

-40% 50%

Source: Compiled by authors from tariff orders of various states

Figure 24: Seasonal Variation in Time of Day tariffs

Seasonal ToD for HT Industry FY25

State	12 AM	1 AM	2 AM	3 AM	4 AM	5 AM	6 AM	7 AM	8 AM	9 AM	10 AM	11 AM	12 PM	1 PM	2 PM	3 PM	4 PM	5 PM	6 PM	7 PM	8 PM	9 PM	10 PM	11 PM	Energy Charge (Rs./Unit)
Andhra Pradesh (Low Demand)	-12%	-12%	-12%	-12%	-12%	-12%	16%	16%	16%	16%	-12%	-12%	-12%	-12%	-12%				16%	16%	16%	16%			6.30
AndhraPradesh (High Demand)	-12%	-12%	-12%	-12%	-12%	-12%	24%	24%	24%	24%	-12%	-12%	-12%	-12%	-12%				24%	24%	24%	24%			6.30
Himachal Pradesh (June to Au..	-18%	-18%	-18%	-18%	-18%	-18%													18%	18%	18%	18%	-18%	-18%	6.06
Himachal Pradesh (Sep. to Ma..	-12%	-12%	-12%	-12%	-12%	-12%													18%	18%	18%	18%	-12%	-12%	6.06
Madhya Pradesh (Apr to Oct)							20%	20%	20%	-20%	-20%	-20%	-20%	-20%	-20%	-20%	-20%	20%	20%	20%	20%	20%			6.30
Madhya Pradesh (Nov to Mar)	-20%	-20%	-20%	-20%	-20%	-20%																	-20%	-20%	6.30
Punjab (Apr to Mid-June)	-11%	-11%	-11%	-11%	-11%	-11%																	-11%	-11%	6.60
Punjab (Mid-June to Mid-Oct)																			30%	30%	30%	30%			6.60
Punjab (Mid-Oct to Mar)	-15%	-15%	-15%	-15%	-15%	-15%																	-15%	-15%	6.60
Uttar Pradesh (Apr to Sep)	15%	15%	15%			-15%	-15%	-15%	-15%	-15%										15%	15%	15%	15%		7.10
Uttar Pradesh (Oct to Mar)	-15%	-15%	-15%	-15%	-15%													15%	15%	15%	15%	15%	15%	-15%	7.10
Uttarakhand (Summers)	-25%	-25%	-25%	-25%	-25%	-25%	-25%												30%	30%	30%	30%	30%	-25%	6.40
Uttarakhand (Winters)	-25%	-25%	-25%	-25%	-25%	-25%	30%	30%	30%										30%	30%	30%	30%	-25%	-25%	6.40
West Bengal (Monsoon)	-26%	-26%	-26%	-26%	-26%	-26%												21%	21%	21%	21%	21%	21%	-26%	5.93
West Bengal (Summers)	-27%	-27%	-27%	-27%	-27%	-27%												21%	21%	21%	21%	21%	21%	-27%	5.95
West Bengal (Winters)	-26%	-26%	-26%	-26%	-26%	-26%												21%	21%	21%	21%	21%	21%	-26%	5.91

Incentive / Penalty(%)

-40% 50%

Source: Compiled by authors from tariff orders of various states

Annexure 11: Status of franchisees in India

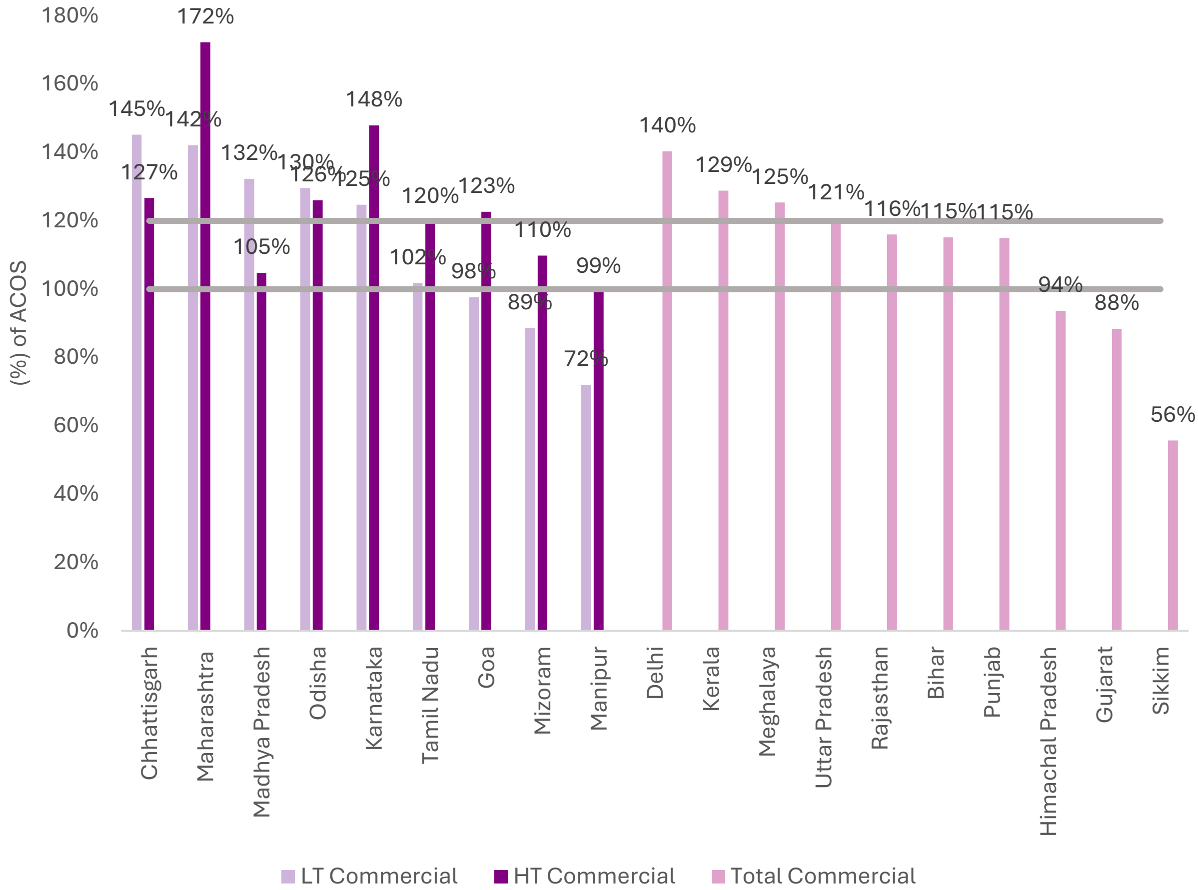
Table 46: Status of franchisees in India

State	Company Appointed as per contract	Area covered	Status
Bihar	1. Essel Vidyut Vitaran	Muzaffarpur	Inability to meet commitments as per contract
	2. India Power Corporation Ltd.	Gaya	Non-payment of dues
	3. SPML Infrastructure Ltd	Bhagalpur	Inability to meet commitments as per contract
Jharkhand	1. Tata Power Ltd.	Jamshedpur	Inability to takeover operations
	2. CESC Ltd.	Ranchi	Inability to takeover operations
Madhya Pradesh	1. Essel Utilities	Gwalior	Inability to takeover operations
	2. Essel Utilities	Ujjain	Inability to takeover operations
	3. Essel Utilities	Sagar	Inability to takeover operations
Maharashtra	1. Torrent Power Ltd	Bhiwandi	Operating since FY07 contract renewed in 2017
	2. CESC Limited	Malegaon	Operating since FY20
	3. Torrent Power Ltd	Shil, Mumbra & Kalwa (SMK) sub-divisions under Thane Urban Circle	Operating since FY20
	4. GTL Infrastructure	Aurangabad	Non-payment of dues
	5. Crompton Greaves	Jalgaon	Non-payment of dues
	6. Spanco Limited	Nagpur	Non-payment of dues
Meghalaya	1. FEDCO	Mawkyrawat, Mawsynram, Nangalbibra and Phulbari	Operational since 2019
	2. Sai Computers	Dalu	Operational since 2019
Odisha	1. Enzen	Dhenkanal, Chainpal and Angul	Termination around takeover by private DISCOMs
	2. Riverside Utilities Private Ltd.	Cuttack, Athagarh and Salipur	Termination around takeover by private DISCOMs
	3. Seaside Utilities Private Ltd.	Nimapara	Termination around takeover by private DISCOMs
	4. FEDCO	Khurda, Puri, Balugaon and Nayagarh	Termination around takeover by private DISCOMs
Rajasthan	1. TP Ajmer Distribution Limited (TPADL)	Ajmer	Operational since July 2017
	2. CESC Limited	Kota	Operational since Sep 2016
	3. CESC Limited	Bharatpur	Operational since Dec 2016
	4. CESC Limited	Bikaner	Operational since May 2017
Tripura	1. Sai Computers	Kailashahar	Operational since 2020
	2. FEDCO	Ambassa, Manu, Mohanpur and Sabroom	Non-payment of dues
Uttar Pradesh	1. Torrent Power Ltd	Agra	Operational since 2009
	2. Torrent Power Ltd	Kanpur	Inability to takeover operations

Source: Authors analysis based with inputs from similar compilation in (Chitnis A. , 2024)

Annexure 12: Extent of cross-subsidy in HT and LT Commercial tariffs

Figure 25: Commercial average tariffs as a percentage of the average cost of supply in FY23



Note: This analysis is based on the actual ACOS for the year and actual average tariffs based on net ARRs, actual category-wise sales and category-wise revenues actually billed. In that sense, the tariff depicted here in relation to the cost of supply will vary from data in centralised databases such as REC's report on Key Regulatory Parameters of Power Utilities and CEA's report on Tariff and Duty of Electricity Supply in India. This is because both of these reports capture tariffs and costs projected by the SERC and not the actual tariffs billed and costs incurred. Actuals provide a better understanding of cross-subsidy requirements than projections because there is significant variation not just in cost and revenue but also in sales.

Category-wise LT and HT distinction in sales and revenue was not clear with data reported in Uttar Pradesh and Delhi, which is why the data is reported for Total Industrial category.

Source: Authors' analysis based on true-up orders and true-up petitions for FY23, annual audited financial statements/reports of DISCOMs

Annexure 13: Impact of DISCOM revenue of levy of open access charges on captive

The consumption from captive sources as reported by CEA for FY23 used to estimate captive consumption. The applicable CSS and AS charges were utilised to estimate the revenue which could have been recovered if these charges were applicable on captive consumption in the state. Any additional duty on captive as compared to open access is netted from this revenue to estimate the net impact of differential charges on captive consumers.

Table 47: Impact of DISCOM revenue of levy of open access charges on captive

State	Captive Sales	Cross Subsidy Surcharge	Additional Surcharge	Total	Impact of exemption of charges	Additional Revenue earned from Duty on captive	Net Impact of exemption
	MU	₹/unit	₹/unit	₹/unit	₹ Cr.	₹ Cr.	₹ Cr.
Andhra Pradesh	8717	1.5	0.0	**1.5**	1308	-654	1961
Bihar	687	2.5	2.1	**4.6**	317	9	308
Gujarat	20545	1.6	0.8	**2.4**	4849	-1189	6037
Haryana	3406	1.2	1.1	**2.3**	790	0	790
Karnataka	11713	2.0	1.2	**3.2**	3690	-618	4308
Kerala	1139	1.5	0.0	**1.5**	175	-10	185
Madhya Pradesh	4971	1.4	1.3	**2.6**	1312	0	1312
Maharashtra	11951	1.7	1.4	**3.1**	3645	565	3080
Odisha	49219	0.7	0.0	**0.7**	3347	833	2514
Punjab	3458	0.7	0.9	**1.6**	539	-368	907
Rajasthan	7372	1.7	0.9	**2.6**	1887	362	1526
Tamil Nadu	7516	1.9	0.0	**1.9**	1398	-75	1473
Telangana	4003	1.8	0.4	**2.1**	857	76	781
Uttar Pradesh	11468	2.8	0.0	**2.8**	3234	0	3234
Total	**146166**			**1.87**	**27348**	**-1069**	**28417**

Source: (CEA, 2024a; REC, 2025) along with regulatory orders and state government notifications

Annexure 14: Impact of interest sub-vention on bonds for 5 year period

The impact of one year interest sub-vention on the bond coupon rate is estimated for when the loss takeover through bonds is one-time and, on a tranche, -wise basis in Table 48.

Table 48: Impact of interest sub-vention on bonds for 5 year period

State	Interest Subvention of 1% for 5 years Incentive (₹ Cr.)					
	One-time	**Tranche -wise**				
Unit		Year 1	Year 2	Year 3	Year 4	Year 5
Andhra Pradesh	813	48	100	157	220	287
Assam	27	2	3	5	7	9
Bihar	436	26	54	84	118	154
Chhattisgarh	252	15	31	49	68	89
Gujarat	-	-	-	-	-	-
Haryana	705	42	87	137	190	249
Himachal Pradesh	107	6	13	21	29	38
Jharkhand	528	31	65	102	143	187
Karnataka	809	48	100	157	219	286
Kerala	908	54	112	176	245	321
Madhya Pradesh	1,886	111	233	365	510	667
Maharashtra	1,010	60	125	196	273	357
Manipur	8	0	1	1	2	3
Meghalaya	122	7	15	24	33	43
Odisha	-	-	-	-	-	-
Punjab	225	13	28	44	61	80
Rajasthan	2,329	138	288	451	629	823
Tamil Nadu	4,277	253	528	828	1,155	1,512
Telangana	1,857	110	229	360	502	657
Tripura	33	2	4	6	9	12
Uttar Pradesh	2,460	145	304	476	665	870
Uttarakhand	142	8	18	27	38	50
West Bengal	18	1	2	4	5	6
Total	**18,951**	**1,120**	**2,340**	**3,670**	**5,120**	**6,701**

Source: Authors' analysis based on data from (PFC, 2025; RBI, 2024)

Annexure 15: State-wise eligible Capital investment reimbursement (₹ Cr.)

Table 49: State-wise eligibility quantum for capital investment reimbursement

State	Capital Investment Reimbursement
Unit	₹ Cr.
Andhra Pradesh	639
Assam	21
Bihar	346
Chhattisgarh	200
Gujarat	-
Haryana	555
Himachal Pradesh	84
Jharkhand	417
Karnataka	633
Kerala	715
Madhya Pradesh	1,483
Maharashtra	800
Manipur	6
Meghalaya	97
Odisha	-
Punjab	177
Rajasthan	1,821
Tamil Nadu	3,363
Telangana	1,473
Tripura	27
Uttar Pradesh	1,934
Uttarakhand	112
West Bengal	14
Total	**14,917**

Source: Authors' analysis based on data from (PFC, 2025; RBI, 2024)

Annexure 16: Share of agricultural sales to total sales across states

Table 50: Share of agricultural sales to total sales across states

State	% of Agricultural sales to total sales								
	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22	FY23
Chandigarh	0%	0%	0%	0%	0%	0%	0%	0%	0%
Delhi	0%	0%	0%	0%	0%	0%	0%	0%	0%
Haryana	30%	27%	28%	26%	24%	24%	24%	20%	18%
Himachal Pradesh	7%	1%	1%	1%	1%	1%	1%	1%	1%
J&K and Ladakh	5%	4%	4%	4%	4%	3%	4%	4%	4%
Punjab	26%	28%	28%	26%	22%	24%	26%	24%	24%
Rajasthan	38%	40%	42%	43%	39%	41%	44%	41%	39%
Uttar Pradesh	18%	18%	19%	20%	19%	19%	20%	19%	18%
Uttarakhand	1%	1%	1%	4%	4%	2%	2%	3%	3%
Chhattisgarh	18%	21%	22%	24%	23%	22%	25%	24%	23%
Gujarat	22%	15%	20%	15%	15%	13%	14%	13%	17%
Madhya Pradesh	36%	41%	38%	35%	36%	39%	42%	40%	39%
Maharashtra	25%	25%	23%	24%	26%	23%	27%	26%	24%
Goa	1%	1%	1%	1%	1%	1%	1%	1%	1%
Andhra Pradesh	26%	25%	28%	25%	23%	27%	18%	22%	15%
Telangana	32%	29%	35%	39%	41%	35%	38%	36%	33%
Karnataka	33%	34%	37%	36%	37%	36%	36%	36%	32%
Kerala	2%	1%	2%	2%	2%	2%	2%	2%	2%
Tamil Nadu	16%	14%	14%	13%	14%	14%	15%	13%	14%
Puducherry	3%	2%	2%	2%	2%	2%	3%	2%	2%
Lakshadweep	0%	0%	0%	0%	0%	0%	0%	0%	0%
Bihar	3%	3%	2%	3%	3%	4%	5%	4%	12%
Jharkhand	1%	1%	1%	1%	1%	1%	1%	1%	1%
Odisha	1%	2%	2%	2%	3%	3%	3%	3%	2%
West Bengal	4%	4%	3%	3%	3%	3%	3%	2%	3%
Sikkim	0%	0%	0%	0%	0%	0%	0%	0%	0%
A & N Islands	0%	0%	0%	0%	0%	0%	0%	0%	1%
Arunachal Pradesh	0%	0%	0%	0%	0%	0%	0%	0%	0%
Assam	1%	1%	1%	0%	1%	1%	1%	1%	1%
Manipur	1%	0%	0%	0%	0%	0%	1%	1%	1%
Meghalaya	0%	0%	0%	0%	0%	0%	0%	0%	0%
Mizoram	0%	0%	0%	0%	0%	0%	0%	0%	0%
Nagaland	0%	0%	0%	0%	0%	0%	0%	0%	0%
Tripura	4%	4%	5%	4%	4%	4%	4%	4%	5%

Source: Compiled from CEA General Review (Various years)

India's electricity distribution companies (DISCOMs) face yet another major financial crisis. With ₹7.08 lakh crore in accumulated losses growing at 8% annually, the sustainability of the entire power sector is at risk. Despite multiple bailout schemes over two decades, the fundamental causes of these mounting losses remain unresolved.

The report analyses the key drivers of DISCOM indebtedness and discusses comprehensive strategies to address legacy losses, manage existing operational inefficiencies and respond to emerging trends that have the potential to threaten future DISCOM financial viability. Recent developments in renewable energy and electricity storage, infrastructure investments, and market evolution have created conditions that make structural changes in the role of DISCOMs feasible.

The analysis and suggestions detail a path forward for the financial recovery of DISCOMs by treating their turnaround as a strategic enabler of India's economic growth and energy transition objectives. The approach can be adapted to the state context and requires coordinated efforts from multiple agencies at the central and state level as well as investment in institutions over a five to seven year period. It offers policymakers a roadmap for sustainable sector transformation rather than a temporary relief as the sector moves from one financial crisis to another.

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