Submitted to Ministry of Power November 2025

Submissions on Draft Electricity (Amendment) Bill, 2025

CEEP
CENTRE FOR ENERGY, ENVIRONMENT & PEOPLE

Table of Contents

1. Introduction

The Ministry of Power issued a notice on 09th October 2025 wherein it published the Draft Electricity (Amendment) Bill, 2025 (*hereinafter referred to as the Bill*) proposing to amend the Electricity Act, 2003 (*hereinafter referred to as the Act*). The Bill was published along with an Explanatory Note and a comparative statement detailing existing provisions and the deviations in the Bill and the justification for such deviation. The Ministry had also invited comments and/or suggestions on the Bill.

This is a submission from Centre for Energy, Environment and People (Jaipur, RJ) in response to the invitation from the Ministry. The submissions have been structured as follows:

a. General Comments on Power Sector Reforms
b. Section-wise Comments on the Draft Bill

We therefore request that these submissions are taken on record. We further request that we be provided an opportunity to make our submissions during any public hearing held by the Ministry on this Bill.

2. General Comments Power Sector Reforms

2.1. Purpose of the Act: Tackling Energy Trilemma and Governance Reforms

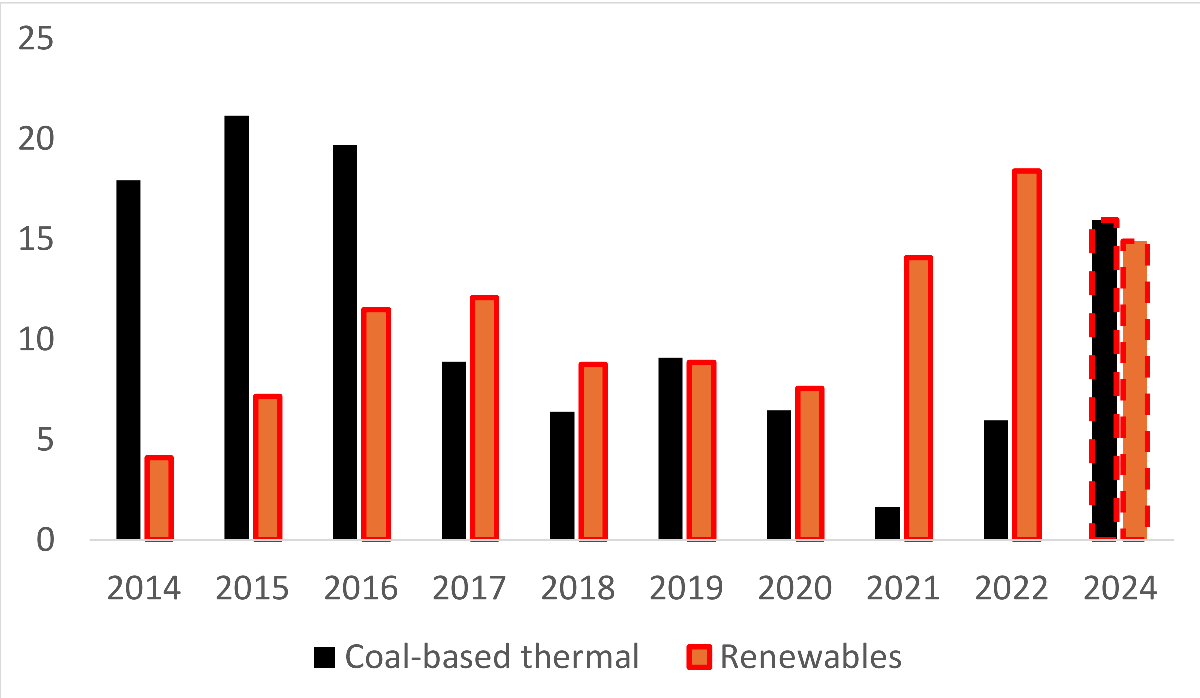
Electricity has intricate links with economic growth, social development, and environmental degradation. Hence, national power policies are supposed to maintain a delicate balance between energy security, energy affordability, and sustainability, otherwise known as energy trilemma. On the same line, the Bill seeks to ensure "*affordable, reliable, and clean electricity for all while enabling a seamless and equitable energy transition*". These amendments seem to be addressing three key challenges of contemporary energy governance, energy security, energy affordability, and energy sustainability.

However, the Bill is clearly more tilted towards reducing industrial tariffs, abolishing cross-subsidies, and has remained silent over phasing-out of existing or reducing investment in fossil-fuel based thermal power plants. Hence, the Bill completely ignores energy equity and affordability completely, and sustainability partially in favour of energy security.

India not only has deep inequality in power consumption across income classes, but also in terms of energy prices paid by poor and rich consumers. Low-income households with energy access have disproportionately high expenses on energy (MOSPI 2024). The recent *Household Consumer Expenditure* survey shows that households at the '*bottom income decile*' spend twice as much on energy as the '*top income decile*', which indicates inequalities in energy access across the population. Despite these realities, the Bill has proposed ending erstwhile cross-subsidies and design cost-reflective tariffs, which will increase the cost of electricity for consumers at bottom income quantile significantly. The increased cost of electricity will force consumers from bottom income quantile to shift for less cleaner sources of energy, which will have an impact on their health and livelihoods. It will directly impact the sustainable development goal of alleviating poverty. Therefore, adequate, reliable, and affordable energy is not only key for economic growth, but also has direct impact on human development, and social welfare. Additionally, on one side withdrawal of cross-subsidies will have serious implications for energy equity, and on the other it will have a minimal impact on the competitiveness of MSME firms. So, there is no rationale for trading off energy equity for gains in global industrial competitiveness. It seems to be a scheme to provide cheaper power to industrial consumers and leaving vulnerable consumers at the mercy of markets.

India is the third largest emitter, and all pathways to global carbon neutrality go through India. We draw 72 percent power from coal, which is the dirtiest source of electricity. While the Bill envisages to increase share of non-fossil fuels to 50 percent in the consumption, it does not mean decline in coal-based thermal power capacity. Unfortunately, it remains awfully silent on reducing dependence on coal, tightening new investments in coal, and retirement of existing coal-based thermal assets. In fact, investments in coal-based thermal assets have increased over last few years (*Figure 1*).

Figure 1: Year wise addition in generation capacity in GW



Source: Ministry of Power 2024

It is true that energy needs of every country are different, and India is no exception to that. However, what the Bill has failed to offer is to provide a transparent, accountable, and responsive governing mechanisms to manage energy trilemma. The country should be aware of the trade-offs in the process of making a choice between a coal-based thermal power plant and a renewable energy plant. The government may opt for fossil-fuel based electricity, in case its impact on either energy security or affordability significantly outpaces the losses on environmental dimensions.

For example, the Government of India has continued to invest in coal-powered thermal power plants despite its commitment to reduce the environmental and social externalities of coal under the guise of energy security, economic growth, and competitive advantage (Roy & Schaffartzik, 2021)[1]. In the absence of reliable and timely data on various attributes of energy trilemma, it is difficult to understand whether economic growth and competitive advantage, claimed by the Government of India, due to coal compensate for its impact on nature and people and how those benefits will be distributed to the communities and nature. Hence, even a stunted energy trilemma backed by access to timely and reliable data can help civil society organisations (CSOs) and the public to hold government accountable within a democratic institutional environment (Gaventa & McGee, 2013)[2].

It is difficult for CSOs and general pubic to demand accountability from a technologically sophisticated, financially complex, politically sensitive, and environmentally important sector without the mechanisms to hold governments accountable for its actions. Without legal and institutional mechanisms, the government can obfuscate data and remain unaccountable. Hence, the future lies in the governance structures that provide institutional spaces to civil society to track the progress towards environmentally benign and socially just energy and hold the State accountable in the long run.

2.2. Unbalancing federal balance: politically disempowering, financially burdening

Electricity was the part of Provincial List under Government of India Act, 1935, but it has been moved under Concurrent List by the Constituent Assembly due to growing importance of electricity in national development, especially for inter-state grid development and industrialisation. Under Electricity Supply Act, 1948, the Central Government has limited role in coordination and planning of electricity and state governments were free to make laws, plan, and develop electricity sector within their state across generation, transmission, and distribution. The 2003 Act was a major policy intervention in reforming and liberalising power sector. It has separated regulatory and policy-making function within the power sector. While, the Central Electricity Regulatory Commission (*CERC*), the central regulatory body has power to frame rules, set standards, and performance benchmarks as a guiding tool to improve power sector, it was a prerogative of the state ERCs to follow such guiding principles.

Additionally, Central Government has power to make rules by notifications for carrying out '*provision* of the Act' under Section 176 (1). However, Central Government has used this provision frequently in past three years to encroach powers of CERC and state ERCs, the exercise of which has been opposed by bodies such CERC. The Bill has now proposed to replace the word '*provisions* of the Act' in Section 176 (1) with '*purposes* of the Act'. The proposed amendment has not only given formalised explicit power to the Central Government to make rules and regulation in such areas but has also expanded the scope beyond the

[1] Roy, B., & Schaffartzik, A. (2021). Talk renewables, walk coal: The paradox of India's energy transition. *Ecological Economics*, *180*, 106871. https://doi.org/10.1016/j.ecolecon.2020.106871

[2] Gaventa, J., & McGee, R. (2013). The Impact of Transparency and Accountability Initiatives. *Development Policy Review*, *31*(s1). https://doi.org/10.1111/dpr.12017

provisions of Act. Hence, Central Government can exercise power beyond the traditional area such as transmission planning, setting up national targets, and other areas. It will result in disempowerment of state government in terms of policymaking and state ERCs in term of regulating the power sector within their jurisdiction.

The Bill also proposed to establish an Electricity Council under the chairmanship of Central Minister of Power and convenorship of Union Secretary of Power. It will have an advisory role in coordination in implementation, facilitation of consensus over reforms, and policy measure to achieve '*objectives*' of this Act. While the Council has an advisory role, the previous experiences shows that these councils result in consolidation of power in the centre as the Union Government dominates such committees and result in gradual loss of autonomy of the state governments (Kir, 2021)[3]. Further, such centralised coordination councils often ignore the third tier of government, that is the local governing bodies, and make them more vulnerable than before (Bhutani & Mishra, 2018)[4]. Progressively, the union and state government should have allowed local bodies to take control of distribution of power, decentralised renewable energy, and other aspects of localised policymaking.

While the states have been disempowered in terms of policymaking and regulation of sector, the Bill will increase financial burden of the state government significantly. Section 61(g) of the Bill mandates abolition of cross-subsidies within five years with respect to railways, manufacturing and metro rail service and cost-reflective tariffs, which means that tariff of agricultural and poor domestic households will increase. The Bill has defined Manufacturing Enterprises in Section 2(42a) as per the First Schedule of Industrial (Development and Regulation) Act, 1951, which covers almost every industry, implying that there will be no cross-subsidies within 5 years. However, it will also increase financial burden on the state governments if they choose to provide direct subsidies to keep electricity prices at existing levels for the end consumers. Conversely, they must pass on the cost to the end consumers and risk the implications in state elections. It means they either bear the pollical cost of increasing tariffs or pay financial cost. In any way, it will significantly shrink their political power and will result a more skewed federal balance.

2.3. Rationalising benefits of CPSUs (FI, Coal, Railways, NTPC)

The Bill emphasises cost-reflective tariff design as essential for financial sustainability of distribution companies (*discoms*). However, this framework exhibits selective application of cost-reflectivity that merits critical examination. Cost-reflective principle is rigorously applied downstream to discoms and consumers, yet systematically bypassed upstream where natural monopolies operate without competitive discipline.

[3] Kir, A. (2021). India's Goods and Services Tax: A Unique Experiment in Cooperative Federalism and a Constitutional Crisis in Waiting. *Canadian Tax Journal/Revue Fiscale Canadienne*, *69*(2), 391–445. https://doi.org/10.32721/ctj.2021.69.2.kir

[4] Bhutani, S., & Mishra, A. K. (2018). Fiscal federalism and decline of the third tier in India: A case for sharing of the new GST. *Indian Journal of Economics and Development*, *6*(11), 1–10.

Upstream entities, particularly Central Public Sector Undertakings (CPSUs) such as the transmission entities (e.g. PowerGrid), fuel supply (e.g. Coal India), NTPC, and even Railways operate in protected markets with captive consumers and limited business competition. These entities maintain substantial margins and cost structures that face no competitive pressure to optimise or innovate. PowerGrid's transmission charges, established without alternative routing options, incorporate inefficiencies which the discoms cannot negotiate. Coal India's thermal coal pricing, something beyond discoms' powers of negotiation, reflects monopoly protection rather than efficiency benchmarking. NTPC's generation costs embed aging asset bases and capital recovery assumptions passed automatically to obligated offtakes. Railway freight surcharges operate outside competitive markets and largely cross subsidising their passenger business. Each upstream entity transfers its cost structure downstream without challenge and protest from the downstream entities. Despite operating in these low competition markets, their Return on Equities (*RoEs*) are much higher.

The fundamental contradiction is stark. While cost-reflective tariffs demand that discoms rationalise operations and pass savings to consumers, yet these same discoms are price-takers on upstream inputs they cannot negotiate. Rationalising downstream tariffs while protecting upstream monopoly structures creates a one-directional cost cascade where inefficiencies flow downward and the reform pressure converges on them.

True cost-reflective tariff design requires consistent application of it across the value/supply chain where upstream entities must face equivalent rigor in cost rationalisation, margin audit, and competitive benchmarking. Their margins should be competitive, and pricing should reflect the standards of the industry, and their capital recovery should be contestable. Without concurrent upstream structural reform, downstream tariff rationalisation remains selective application of efficiency principles, legitimising upstream inefficiencies rather than solving the sector's financial crisis.

2.4. Return on Equity: Rationalisation and Treatment Issues

Under Section 61 of the Act, and the tariff regulations of the CERC and state ERCs, RoE is a key component of the cost-plus tariff framework, allowing returns on the equity portion of a regulated entity's capital investment. The RoE serves as a critical policy instrument designed to compensate utilities for the opportunity cost of equity capital, encourage sustained public and private investment in the power sector, and maintain a balance between consumer affordability and investor confidence.

The RoE mechanism was particularly significant in the early years of reform, when the power sector faced considerable uncertainties and investment risks. In current scenario, however, the sector has evolved substantially. Private generators now primarily invest through competitive bidding, while short- and medium-term power contracts are discovered through reverse auctions. Besides, three functional power exchanges facilitate transparent price discovery. These developments reflect a maturing market with reduced investment risks and greater regulatory and commercial stability. Public sector entities, including CPSUs and State

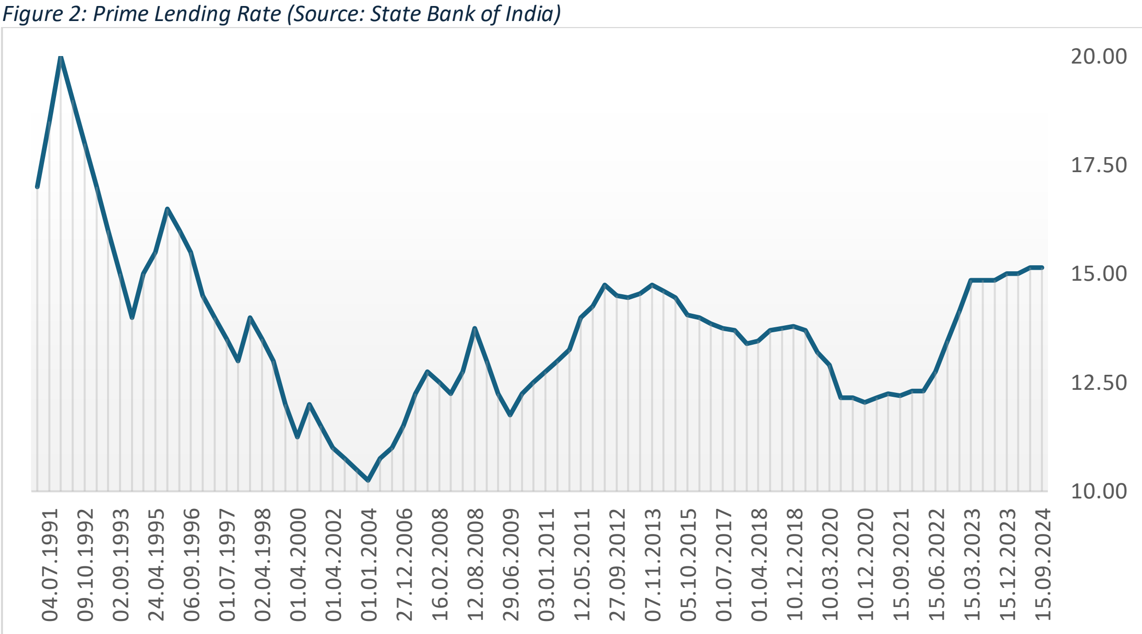
Public Utilities (SPUs), operate entirely under cost plus regulated tariff frameworks as mentioned in previous section. This structure ensures full recovery of costs such as operations and maintenance, interest, and depreciation, along with an assured RoE.

2.4.1. Need for Rationalisation

The RoE framework, while effective and necessary in the past, now requires rationalisation to reflect current market realities. Several considerations support this need:

a. **Alignment with Macroeconomic Trends:** Over the past two decades, India's prime lending rate has fluctuated between 10.25 and 20 percent, indicating significant variation in risk-free returns. Yet, RoE has remained static at 14 percent to 16 percent. This rigidity leads to mismatches between prevailing interest rates and equity returns; consumers end up paying higher tariffs during low-rate periods, while developers earn inadequate returns during high-rate periods.

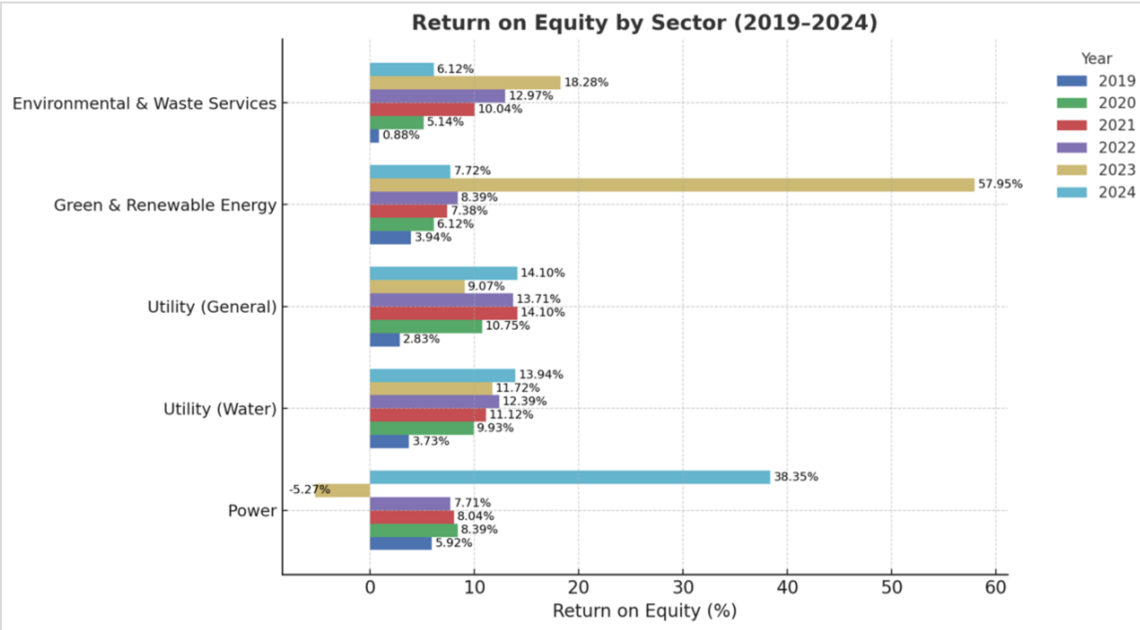
Figure 2: Prime Lending Rate (Source: State Bank of India)



b. **Maturing Market and Reduced Risk Premium:** The Indian power market has matured significantly, with established market-based procurement, functional exchanges, and improved regulatory stability. The overall risk environment has diminished, justifying a lower risk premium in determining RoE.

c. **International Benchmarks:** Globally, regulated RoE levels are considerably lower. For instance, China allows RoE in the range of 8-10 percent, while Germany recently reduced RoE to 5.07 percent for new assets and 3.55 percent for old assets, citing macroeconomic stability. By comparison, India's RoE of 14-16 percent appears high relative to its current cost of capital.

Figure 3: Return of Equity of Various Utilities in Western Europe (Source: Statista)



d. Regulatory Recognition: The CERC in 2013 and 2024 acknowledged the need to rationalise RoE and link it to standard financial benchmarks to reflect market realities. Several stakeholders, including state governments (such as Punjab) and utilities, have argued that RoE should be reduced under the cost plus framework, as generation and transmission companies bear limited risk when all costs are fully recoverable.

2.4.2. Uniform Regulatory Framework, Divergent Performance

Despite operating under a cost-plus framework, State-owned Generating Companies (*State Gencos*) face a distinct set of challenges rooted in their ownership structure and operational context. As state-owned entities, they have limited managerial and financial autonomy, with state governments exerting significant influence over key decisions, often making them susceptible to political considerations. Revenue recovery is typically weak or delayed, as their sole buyers are financially stressed discoms.

Fuel supply management is another persistent challenge, given their dependence, mostly, on long-distance transportation of domestic coal, logistical bottlenecks, and linkage constraints. In many cases, State Gencos are unable to recover their approved RoE, as state governments refrain from passing on higher costs to consumers in politically sensitive tariff environments. State ERCs, citing inefficiencies or underperformance, may also withhold or disallow RoE on prudence grounds.

These factors collectively erode the financial health of State Gencos, constraining their capacity to invest in maintenance, modernisation, capacity augmentation, transition planning, and debt servicing, thereby perpetuating a cycle of operational and financial underperformance. The absence of strong balance sheets or standalone creditworthiness further forces them to rely on borrowings backed by state guarantees or from public financial institutions such as PFC and REC, limiting their access to capital markets and driving up financing costs.

In contrast, CPSUs are relatively insulated from the fiscal and institutional constraints faced by state utilities. They also benefit from stronger representation in regulatory processes, greater institutional autonomy, and policy predictability, alongside assured offtake through central allocation mechanisms. Their low cost of capital, enabled by sovereign guarantees and access to concessional or multilateral financing, further strengthens their competitiveness. These factors collectively underpin superior operational efficiency and financial performance, reinforcing the institutional resilience of CPSUs *vis-à-vis* their state counterparts.

Given the structural differences and uneven risk exposure across entities, the proposed Bill should adopt a differentiated RoE framework that accounts for institutional, financial, and market realities. A risk-sensitive regulatory approach would help prevent excessive concentration of investment within CPSUs while enabling a more balanced participation of State Gencos. The state governments and state ERCs should also recognise RoE as a legitimate cost component under the cost-plus framework and facilitate its full recovery to strengthen financial sustainability and reinvestment capacity.

2.5. Preservation and fair treatment of Public Sector for Resilience and Transition Efficiency

The Bill inclines towards privatisation to promote efficiency, innovation, and investments in the power sector. As the amendments seek to shape the legal and policy frameworks to guide the power sector in the coming decades, we invite attention to the role of public sector in the context. We argue for the preservation and fair treatment of public sector for promoting healthy competition, enabling critical investments in an evolving regulatory and market environment, and institutionalise resilience to mitigate impact of any unforeseen failures.

2.5.1. Privatisation and Energy Transition: Navigating Uncertainty and Risk of Failure

While India's power sector is quite robust, it also suffers from many challenges. Central and state governments had to intervene and bail out the sector, both generation and distribution companies, at multiple instances. National and global experiences show that privatisation in the utility space does not ensure investments, affordability, and operational efficiency. For example, the privatisation of regional water authorities in the UK led to under investments for replacing ageing infrastructure, raising concerns of environmental lapses and water quality. These private utilities operated in a non-competitive environment under poor regulatory and public accountability. At the same time, they borrowed heavily while distributing large dividends to shareholders, leading to debt accumulation and rising tariffs.

Power sector is a critical sector as national security, economic growth, social development and many critical services such as banking, communications, healthcare demand affordable and reliable supply of electricity. Needless to say, failure is not an option for the sector. However, markets and private companies inherently carry a risk of failure. Once again, national and global experiences offer many instances of failure of privatisation in the power sector, demanding a critical review of India's power sector. Such failures may occur because of the inability of the private sector to navigate, both market and non-market risks. For example, Brazil's power sector reforms of the 1990s, undertaken amid macroeconomic instability and fiscal constraints, were shaped by the broader neoliberal push to reduce the state's role in productive sectors. The government began unbundling state owned utilities and selling distribution companies to private investors. The government sought to attract private investment, improve efficiency, and relieve public debt through privatisation. The privatisation process, however, relied heavily on public financing through the Brazilian Development Bank, the state continued to bear much of the financial risk even as ownership shifted to private hands. When the 1999 currency crisis struck, privatised utilities, now exposed to foreign currency debt and declining revenues, faced severe financial distress. The government was forced to intervene with bailouts financed through higher consumer tariffs, eroding the very fiscal relief privatisation was meant to deliver. The example of Brazil reveals that private players were neither structurally equipped nor financially inclined to bear unforeseen risks. As a result, the state absorbed the risks, consumers paid dearly while public resources continued to fund the privatisation.

Today, energy transition imposes new challenges for the power sector. Uncertainty of transition roadmap is an inherent characteristic because of emerging technologies, new business models, evolving regulatory frameworks, and untested market instruments. Private sector is very effective at mobilising investments in mature markets where risks are ascertained and returns are assured. However, in the absence of mature markets such as this transition, critical investments are delayed, increasing technical risks (grid stability) and cost of energy transition. This is particularly true for early stages of market development in India. For example, a national energy storage mission was discussed in 2018 but significant capacity addition of battery energy storage came into the system only from 2022 onwards.[5]

2.5.2. Preservation of Public Sector as an Instrument of Resilience and Efficiency

While private sector is often celebrated for its efficiency and profitability, it must be acknowledged that the objectives of the public sector are inherently different. Public sector priorities national agenda of security, growth and social development above profitability. This difference in priorities also implies that the public sector has a bigger appetite for higher risks and lower returns when it comes to investments. Notably, Section 62 of the Act provides regulatory pathways to enable investments through a cost-plus route when markets are not mature for competitive bidding.

More importantly, public sector also contributes to the state's capacity to come in for the rescue in the event of failure of markets or private entities. This capacity can prove to be critical as has been the evident from GRIDCO's role is securing the power distribution in Odisha when privatisation efforts failed miserably in the early 2000s.

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[5] https://www.pv-magazine-india.com/2025/07/08/india-installed-341-mwh-of-energy-storage-capacity-in-2024-says-mercom/

Based on these arguments, we argue for a fair treatment of PSUs and strategic positioning of its role to effectively and efficiently navigate the risks of privatisation and energy transition.

2.6. Addressing Asymmetric Risk Distribution in the Power Sector

The Bill presumes that privatisation shall certainly address the endemic issues of the power sector. This is seemingly based on the assumption that the poor fiscal health in the distribution sector results from poor management, lack of modernisation and technology innovation, and other such factors. However, we argue that the fundamental reality of the sector distinctly reflects that the problems are structural in nature and arise from an uneven distribution of risks across the three verticals: generation, transmission, and distribution.

The unbundling of the power sector enabled by the 2003 Act, separated the functions of electricity generation, transmission, and distribution. Under the regulated regime, the three functions are entitled to similar RoE even though they have significantly different risk profiles. Particularly, the distribution sector is burdened with disproportionately high and complex risks, such as long-term electricity demand, socio-political risks, and transition uncertainty.

2.6.1. Long-term Demand Risk[6]

Since power sector planning for electricity procurement and transmission network development has a typical time horizon of around 10 years or more, long-term demand mapping risk is inherent to the power sector. Given the structure of the sector, this risk is solely concentrated within the distribution sector through long-term power purchase agreements (PPAs). The efficacy of forecasting and planning exercises is often negatively impacted by political narratives surrounding growth and development, and the distribution sector is left with the negative impacts.

2.6.2. Socio-Political Risks

Access to affordable electricity is a key development issue. This implies that the distribution sector is also exposed to a high degree of social and political risks due to the nature of the business. The sector's nature is extremely complex because of the high network spread and by virtue of being a consumer-facing business. Discoms have to navigate socio-political complexities and threats at both the local and state levels. At one end, it affects their ability to recover dues, while at the other end, their revenues are directly impacted due to the increasing ARR-ACS gap and non-payment of subsidies by concerned state governments.

2.6.3. Conundrums of a Utility Sector and Governance Challenges

Power sector planning and power procurement in India are primarily led by the Central and state governments. This implies that, given the nature of the utility sector, investments in the sector are not a function of market demand and competition. Along with the burden of market and non-market risks, state-owned discoms often lack the autonomy to mitigate such risks.

[6] Long term demand risk refers to the uncertainty and deviations in the practice of long-term demand forecasting. This may result in decline in electricity supply standards if demand overshoots planning and increased financial burden because of reduced asset utilisation in cases when demand significantly falls short of projections.

Procurement of power is carried out directly or indirectly through state governments. Regulatory delays, mounting government dues, and inadequate returns on capital further constrain their ability to maintain assets or invest in efficiency improvements.

2.6.4. Distribution Reforms

In light of the aforementioned structural risks and issues, real distribution reforms shall require interventions to address them. For instance, if investments in generation and transmission are exposed to long-term demand risks, markets should evaluate these risks before making investment decisions. However, enabling such instruments can also lead to under-investments in upstream sectors. Hence, a more viable strategy would be to increase public accountability through mandatory disclosures and transparency in decision-making during the planning process. This will, to some extent, counter the influence of vested interests in power sector planning processes.

Furthermore, distribution companies, whether public or private, need to be safeguarded from unfair denial or suppression of their returns on investment. Institutions denied sustenance shall spiral down and fail to meet their objectives, irrespective of their nature of ownership.

Hence, beyond simply promoting privatisation in the distribution sector, we request that the Ministry of Power enable structural reforms that facilitate fair treatment of public and private distribution companies, equitably distribute risks across the entire sector, or at least enable fair management of such risks by the concerned discoms.

2.7. Risks of Multiple Licensing

The Bill proposes changes to Section 14: Grant of licensee. As per the amendment: *"the Appropriate Commission may grant a licence to two or more persons for distribution of electricity through their own or shared distribution system within the same area in accordance with the framework as specified by the Commission*."

This essentially proposes for a parallel licensing, enabling multiple discoms in the same area on the existing network. This approach introduces retail competition without the institutional prerequisite of separating network ownership from retail supply functions, a structural flaw that could be challenging for the regulatory framework to overcome.

Under the amended provision, incumbent public discoms simultaneously serve as network operators (obligated to provide non-discriminatory access) and retail competitors (commercially incentivised to block competitor access). This dual role creates a permanent conflict of interest. The discoms, as a network owner and operator, controls all switching systems, metering infrastructure, network data, and consumer information. Private competitors depend entirely on this same entity's willingness to facilitate their access. This creates information asymmetry making it impossible for regulators to monitor cost effectively.

The amendments further create a fundamentally asymmetrical competitive structure that will systematically disadvantage the public discoms while enabling private competitors to cherry-pick profitable consumer segments. As parallel licensees systematically target high-value consumers (industrial, commercial), incumbent public discoms lose profitable revenue while retaining fixed network costs. Revenue base erosion forces discoms into impossible choices to either absorb deficits or impose unsustainable tariff increases on residual consumers (primarily residential, agricultural, small commercial). This can even lead to declining service quality, poorer reliability of the vulnerable populations (low-income residential, agricultural consumers). Rather than solving existing financial stress of public discoms, parallel licensing accelerates it. Specific concerns on the impact of amended provisions have been discussed in *Section 3.4*. and *Section 3.5.* of these Submissions.

2.8. Towards Truly Cost-reflective Tariff Design

Cost-reflective tariffs are critical for financial sustainability of discoms and promote industrial competitiveness. However, the current tariff design remains fundamentally incomplete, computing only power procurement, distribution losses, operations and maintenance, and administrative overheads. This narrow definition systematically excludes primary cost differentiators in the distribution business. Cost-reflective tariff design must explicitly incorporate the critical and currently invisible cost dimensions.

Truly cost-reflective tariffs must consider the costs associated with the reliability, load factor, load curve characteristic, and power quality requirements which will vary for each category. Current cross-subsidisation of fixed costs into undifferentiated energy charges obscures these cost drivers, preventing rational price signals and perpetuating discom financial deterioration. Until the tariff design captures these complex dimensions, rationalisation remains redistribution, not equity. In-depth submissions on the specific provisions for tariff design have been discussed in *Section 3.3.* of these Submissions.

2.9. Regulatory Reforms and Strengthening: Resources, Capacity and Autonomy

The Regulatory Commissions (CERC and state ERCs) were envisaged under the 2003 Act as independent, quasi-judicial bodies to ensure transparency, accountability, and efficiency in electricity governance. However, despite clear legal provisions establishing their independence, State ERCs often operate under significant government influence, manifested through delayed tariff determinations, *post facto* approvals of power procurement, and reluctance to enforce compliance by state utilities. The result has been the accumulation of large regulatory assets, weak enforcement of tariff discipline, and diminished credibility of the regulatory framework. Even though the Supreme Court reaffirmed the authority of regulatory commissions in power sector matters in its judgment of October 2024[7], and similar other orders, the practical realisation of this autonomy remains contingent upon deeper reforms in institutional design, fiscal independence, and technical capacity.

In this context, although the Bill expands the functions and responsibilities of the commissions and empowers the government to remove their members for non-compliance with the Act, it fails to address the structural and institutional constraints that limit their performance and effectiveness. The Explanatory Note accompanying the Bill identifies delays by regulatory

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[7] *Kerala State Electricity Board Ltd* v. *Jhabua Power Limited & Ors.*, 2024 INSC 768.

commissions as a key factor contributing to poor sectoral performance and the lack of cost-reflective tariffs. But it falls short of examining the underlying causes of these delays or propose remedial measures to resolve them.

2.9.1. Functional Challenges of Electricity Regulatory Commissions

The regulatory commissions face challenges stemming from issues such as lack of full autonomy, inadequate resources and capacity, and procedural delays, all of which constrain their effectiveness and are discussed in detail below.

a. **Institutional and Functional Autonomy:** Even though state ERCs are empowered by law and multiple judicial rulings, they often remain vulnerable to political and state government influence, especially in matters of tariffs, procurement, and ensuring enforcement of directives by utilities. For example, in Tamil Nadu and Rajasthan, discoms have accumulated large regulatory assets, reflecting deferred cost recoveries as regulatory decisions on tariff adjustments are influenced by state governments.

   Their autonomy is undermined by state governments' control over appointments, financial dependence and administrative oversight, and the revolving door between regulators and utilities. Provisions of the Act, such as Section 108, also weaken their discretion by allowing governments to issue "*policy directions*".

b. **Fiscal and Administrative Independence:** Many state ERCs remain dependent on state budgets and grants for their operational expenditure, which compromises their independence. They also lack administrative authority over recruitment and remain dependent on state governments for such approvals. For instance, both the Rajasthan Electricity Regulatory Commission (RERC) and the Assam Electricity Regulatory Commission (AERC) rely largely on staff deputed from other utilities in the electricity sector for their operations.

c. **Enhanced Technical and Human Capacity** The evolving power sector, characterised by renewable energy integration, emerging market mechanisms, and increasing automation, requires technically proficient regulators with expertise in economics, law, engineering, and data analytics. However, many state ERCs already suffer from inadequate staffing and limited expertise in these critical areas.

   As per Forum of Regulators (FoR), regulatory function is a specialised job and there is general scarcity of such talent. Several Commissions have expressed the difficulties faced by them for attracting talent for the specialised tasks needed to assist the Commissions. One of the reasons cited by the FoR is that, unlike central regulators such as SEBI which offer competitive compensation packages with incentives and allowances, electricity regulatory commissions do not provide comparable benefits to their staff. Also, Central sector regulators have their own Rules and Regulations approved by their Board; the State sector regulators generally follow the provisions in their respective state governments.

   Evidence from Rajasthan suggests acute capacity constraints, leading to weak adherence to regulatory frameworks, inadequate auditing and oversight of discom performance, and the outsourcing of critical analytical tasks such as the development of Time of Day (ToD) Tariff Framework and Energy Storage Regulations.

Furthermore, verification of claims made by utilities during regulatory proceedings remain poor; for example, the three discoms of Rajasthan were found to rely extensively on short term power purchases while simultaneously projecting a '*surplus*' position in their tariff petitions.

d. **Procedural Transparency and Public Participation:** Public participation in the commissions' hearings has been a persistent concern, with limited efforts made to address its underlying causes. Most commissions operate from a single location within the state and participation of people from across the state is a common concern. The accessibility of information and documents on regulatory matters also remains poor, further limiting public understanding in an already technical sector. In Rajasthan, digital accessibility remains weak, as most filings, proceedings, and orders are published only as scanned PDF documents that are not legible, or machine readable, thereby constraining transparency and ease of access.

e. **Accountability and Enforcement:** Regulatory oversight for active monitoring of compliance with the regulatory framework, enforcement of directives, investment plans, and service quality standards remains weak across most states. Instituting periodic performance reviews of licensees and ensuring public disclosure of compliance status can enhance transparency and accountability. In Rajasthan, for instance, discoms have repeatedly delayed the submission of ARR petitions and frequently sought extensions, while their compliance with the Commission's directives has remained abysmally poor.

2.9.2. Recommendations for Reforms

Given these challenges, the proposed Bill must go beyond the incremental allocation of new responsibilities and instead tackle deeper structural and efficiency constraints that continue to impede the functioning of the state ERCs. It should incorporate clear and enforceable provisions that establish institutional independence, financial self-sufficiency, professional staffing, transparency, and increased public engagement across all electricity regulatory commissions. The performance of regulators should also be evaluated against measurable indicators, while empowering them to enforce compliance and penalise violations by strengthening the provisions under Section 142 of the Act.

3. Section-wise Comments on the Bill

3.1. Definition of Manufacturing Enterprises under Section 2(42a)

Under the proposed Section 2(42a), the Bill defines *Manufacturing Enterprises* by reference to the First Schedule of the Industries (Development and Regulation) Act, 1951. However, the *Justification* provided in the Bill refers to *Manufacturing Enterprises* covered only under the Micro, Small and Medium Enterprises Development Act, 2006.

The justification explicitly states that the definition aligns with the MSME Act and aims to subsequently exempt small and medium industries from cross-subsidies and surcharges, thereby enhancing their competitiveness. It is pertinent to note that enterprises covered under the MSME Act are defined with reference to the Industries (D&R) Act but subject to investment ceilings in plant and machinery.

The current formulation of the definition, wherein reference is made to the Industries (D&R) Act rather than the MSME Act, substantially departs from the stated justification and, in effect, extends the scope to all manufacturing enterprises, including large ones, which may not require the intended concessions under the Bill.

It is therefore recommended that either the justification or the definition be amended to ensure alignment between the two. If the intent is to include large enterprises within the ambit of the Bill, the rationale for such inclusion should be explicitly stated in the justification.

3.2. Eligibility Criteria for Captive Generation Plants (Section 9)

The proposed amendments in the Bill empower the Appropriate Government to prescribe eligibility criteria for captive generating plants (CGPs) and their users. At present, eligibility is defined under Rule 3 of the Electricity Rules, 2005, framed under the Act. These Rules stipulate that, to qualify as a CGP, captive users must hold at least 26 percent of ownership and consume a minimum of 51 percent of the electricity generated on an annual basis.

However, the proposed provision introduces ambiguity by allowing both Central and State Governments to prescribe eligibility, without specifying which is the "Appropriate Government" in this context. This could lead to inconsistent criteria across states and uncertainty regarding captive status. Moreover, the amendment does not clarify whether the existing 26 percent to 51 percent ownership and consumption criteria will continue to apply or be revised.

It is important to note that many industries establish captive power plants to avoid cross-subsidy surcharges and mitigate risks associated with grid supply. If the proposed amendment introduces stricter eligibility norms or enhanced regulatory scrutiny, industries may lose their captive status and be compelled to procure power at commercial tariffs. This would significantly increase input costs, particularly for energy-intensive sectors such as cement, steel, and textiles, while potentially leaving existing captive assets stranded.

3.2.1. Conclusions and Recommendations

In view of the potential ambiguity introduced by the proposed amendment, it is recommended that the Bill clearly demarcate which CGPs an *Appropriate Government* will be empowered to prescribe eligibility criteria for. Additionally, the Bill should establish a mechanism to address potential conflicts arising from overlapping or conflicting jurisdictions between the Centre and the states. The determination of such criteria should be preceded by a transparent stakeholder consultation process involving state regulators, industry associations, and consumer groups.

Furthermore, to ensure regulatory certainty and protect existing investments, any new eligibility norms should be applied prospectively, allowing existing captive generating plants to retain their current status under the prevailing rules.

3.3. Ensuring Cost Reflectivity in Supply (Section 61)

The Bill rightly mandates that electricity tariffs must reflect the actual cost of supply. It also stipulates that manufacturing enterprises, railways, and metro rail systems shall be fully exempted from cross-subsidies within five years of the Amendment's notification.

In this context, we submit that retail tariffs across consumer categories are presently determined based on average annual costs rather than the actual cost of supply incurred at different stages of the power sector value chain. This approach obscures the degree of cost reflectivity envisaged in the proposed amendment. Therefore, a comprehensive cost rationalisation is essential across the entire electricity value chain, encompassing generation, transmission, and distribution. This rationalisation should include:

- **a.** Eliminating hidden subsidisation in generation by ensuring transparent and competitive cost discovery;
- **b.** Rationalising cost components under regulated regimes to reflect current benchmarks;
- **c.** Adopting transmission pricing frameworks that mirror actual network usage and losses, rather than aggregated average costs; and
- **d.** Designing retail tariffs to incorporate parameters such as time-of-use, reliability levels, contribution to system peak demand, and other system-level costs.

3.3.1. Cost Reflectivity in Distribution

The cost of electricity distribution is presently determined under a cost-plus framework with defined benchmarks for losses, operational performance, expenditure norms, and returns on capital. However, tariff determination continues to rely on average annual costs rather than the actual cost of supply, differentiated by voltage level, consumer load characteristics, reliability standards, and other system-level parameters. Cost reflectivity at the distribution level can be strengthened by incorporating the following dimensions into tariff design:

- **a. Reliability and Quality of Supply:** Distribution companies deliver varying levels of supply reliability and quality across consumer categories, depending on consumer type, demand profile, and geographical location. For instance, an industrial or commercial consumer in a capital city typically enjoys higher reliability compared to a household in a remote village. The additional costs incurred to contract reliable power, maintain infrastructure, and deliver higher service quality are currently socialised across all consumers.

  Tariff design should therefore incorporate a reliability premium for consumers receiving superior service quality, based on metrics such as interruption indices, voltage/frequency deviations, and the number of dedicated feeders.
- **b. Power Procurement Cost Reflectivity:** Consumer usage patterns and their contribution to system load profiles are not adequately reflected in tariff

determination. For example, discoms incur significant additional costs to meet high demand certain times of day for specific consumer groups. This time-of-day consumption variation where generation, transmission, and distribution costs vary multi-fold between peak and off-peak hours remains completely unaccounted.

Retail tariffs should also align with marginal and source-wise procurement costs, enabling accurate energy accounting and equitable cost attribution. This alignment would prevent unfair socialisation of variable procurement costs arising from renewable generation and short-term market purchases.

c. **Voltage-Level Cost Differentiation:** The tariff design should explicitly account for voltage-wise costs and technical losses by incorporating the cost of supply at EHT, HT, and LT levels, including transformer and line loss ratios, and corresponding O&M costs.
d. **Network and Locational Factors:** Distribution costs vary significantly across urban, semi-urban, and rural areas due to differences in consumer density, infrastructure requirements, and loss levels. Locationally differentiated tariffs or zonal cost accounting can better reflect these variations.
e. **Distributed and RE Integration Costs:** Large consumers adopting renewable energy often receive incentives without bearing the full system integration costs. Tariff design should reflect the grid integration, balancing, and ancillary service costs associated with renewable energy adoption.
f. **Fixed Cost Recovery:** Discoms procure power primarily through Annual Fixed Charges (payable irrespective of actual consumption) and Energy Charges (linked to energy purchased). However, their revenue structure does not mirror this procurement pattern due to poor tariff design. The tariff structure should be revised to ensure proportionate fixed cost recovery and enhance cost reflectivity.

3.3.2. Cost Reflectivity in Transmission

The inter-state (ISTS) transmission pricing in India has evolved from simple energy-based charges to mechanisms such as the Point of Connection (PoC) and General Network Access (GNA) frameworks. However, intra-state (InSTS) transmission pricing across many states continues to face challenges, including pricing distortions and inconsistent methodologies. To enhance cost reflectivity, InSTS transmission pricing should move toward models that more accurately represent actual network usage, capacity utilisation, and incurred costs.

3.3.3. Cost Reflectivity in Generation

As noted in Section 2.3 of General Comments section of these Submissions, entities such as Coal India, NTPC, and the Railways now operate in relatively mature and protected markets, unlike the initial stages of power sector development when competitive and institutional frameworks were still evolving. Coal India's thermal coal pricing reflects its monopolistic position, while NTPC's generation costs are automatically passed through to obligated off-takers, ensuring stable and high returns on equity. Similarly, railway freight surcharges used to cross subsidise passenger transport significantly increase coal transportation costs, thereby inflating the overall cost of power generation.

3.3.4. Concluding Remarks

The aforementioned inefficiencies across the sector's value chain must be addressed to achieve genuine cost reflectivity; As noted in Section 2.6 of these Submissions, discoms are structurally poorly positioned where all the adverse effects of these inefficiencies are parked. Expecting discoms alone to rationalise operations and pass on savings to consumers will not therefore be successful and may possibly bear the risk of merely shifting price distortions to other parts of the value chain.

3.4. Multiple Licensees on Shared Distribution Network (Section 14 and Section 42(1))

The Bill has noted that the current regime, which allows multiple licensees to operate in an area, forces the licensees to setup their own distribution network. This practice leads to duplication of network assets, and results in wastage of scarce capital and land resources. As such, the Bill has proposed that allowing multiple licensees to operate on a shared network would promote competition while preventing said wastage. In pursuance of this proposal, the Bill has sought to amend Sixth Proviso to Section 14 of the Act with the following effects:

a. The state commissions may now grant two or more distribution licence in an area, and permit these multiple licensees to operate on a shared network;
b. The licence must be granted as per a framework specified by the state commissions; the commissions have been empowered to introduce regulations on such a framework vide amendments proposed to Section 181 (*Powers of state commissions to make regulations*).

We submit that the proposed amendments are in the right direction, but they lack certainty and nuance to ensure that competition is promoted without reintroducing inefficiencies through network duplication. The following observations are submitted in this regard:

3.4.1. For the First Part of Amendment to Section 14

A discretionary power to state commissions empowering them to grant more than one licence in the same area and allow the licensees to operate either on a separate or on a shared network is contrary to the objective of promoting competition while discouraging resource and capital wastage. Such discretion would lead to duplication of network and resource wastage, particularly in jurisdictions where the framework envisaged in the second part of the amendment to Section 14 may not have been notified.

We therefore recommend that the first part of the proposed amendment must be revised so as to mandate the state commissions to allow two or more licensees only on a shared network. A discretion to build, operate and maintain a separate network in the same area may only be allowed under exceptional circumstances. These exceptional circumstances may include topographically isolated areas where shared network infrastructure is technically infeasible, or emergency situations requiring rapid network restoration. Such exceptions can be specified in the framework proposed to be specified by the state commission, with objective criteria to prevent arbitrary application.

3.4.2. Establishment of a Distribution System Operator (DSO)

Given the proposal in the Bill to permit multiple distribution licensees to operate over a shared network, it becomes essential to establish an independent institutional entity responsible for operational coordination, network data integrity, and non-discriminatory access management. This entity would function as a neutral system operator, distinct from any licensee, and ensure efficient, transparent, and equitable network usage.

In a multi-licensee environment, the absence of a single authority can lead to operational overlaps, energy-accounting discrepancies, conflicting augmentation plans, and disputes over access and quality of service. The DSO framework, as implemented in mature electricity markets (such as the UK's Distribution Network Operators transitioning to DSOs, and the EU's unbundled DSOs), provides a tested institutional model to address these concerns. The DSO ensures grid reliability and competitive fairness while maintaining efficient network operation and planning.

The DSO should be established as a statutorily independent and a regulated entity under the Act, operating under the oversight of the Central and state commissions. Its governance must ensure functional separation from licensees, either by ring-fencing the network owner's operational arm or through creation of a dedicated public authority at the state level.

3.4.3. For the Second Part of Amendment to Section 14

The Bill has proposed amending the second part of the Proviso to require the state commissions to issue two or more licences in accordance with a framework which will be specified by the commissions themselves. The Bill has empowered the state commissions to draft regulations on the frameworks under Section 181(2). This empowerment is a necessary step towards ensuring autonomy of the commissions over operations within the sector.

However, the Bill's omission to specify the essential elements to be covered within the proposed framework may result in significant operational and regulatory uncertainties for distribution licensees owning the network, as outlined below:

a. Operational and Commercial Complexities

Parallel operation of multiple licensees on a shared distribution network presents a range of operational and commercial complexities that warrant careful consideration prior to implementation. These complexities arise primarily from issues of functional coordination across multiple entities using common network infrastructure, and attributing accountability and costs in this shared structure. These complexities are elaborated below:

i. **Reliable and accurate accounting of energy:** The operation of multiple licensees over a common network raises challenges in ensuring accurate metering and energy accounting. Points of interface between licensees and their respective consumer bases must be clearly identifiable to prevent discrepancies in measurement and to avoid potential disputes relating to energy flows, billing accuracy, and loss allocation.

To address these challenges, the framework should incorporate a standardised metering arrangement that clearly demarcates points of injection, withdrawal, and inter-licensee exchange through boundary and consumer interface meters. A uniform methodology for allocation of technical and commercial losses among licensees should be prescribed, and the methodology should be supported by audits by or under the regulator. Additionally, a time-bound dispute resolution mechanism specific to energy accounting should be included in the framework to ensure operational continuity and maintain the financial integrity of multi-licensee operations.

The DSO (proposed previously) may monitor and coordinate operations of all the licensees, and be responsible for overseeing metering infrastructure, maintaining network data integrity, and ensuring neutrality in the energy accounting and resource allocation processes.

ii. **Cost-sharing and infrastructure augmentation:** The shared use of distribution assets complicates the attribution of costs for maintenance, reinforcement, and augmentation of network infrastructure. In the absence of clear norms, disputes may arise regarding proportional contribution, timing of augmentation, and recovery of associated costs. These uncertainties can delay investment decisions and affect the network expansion activities.

The framework must therefore establish transparent methodologies for sharing costs of infrastructure augmentation, including mechanisms for determining the requirement of augmentation and attributing responsibility for such augmentation. Additionally, pre-agreed escalation and dispute resolution mechanisms should be established to address conflicts arising from augmentation decisions.

Here, the DSO may be entrusted with overseeing network operation and maintenance, coordinating outages, managing congestion, and facilitating equitable recovery of network augmentation costs.

iii. **Treatment of infrastructure upon licensee exit:** The possibility of a licensee exiting the market, whether due to insolvency, licence cancellation, or voluntary withdrawal, creates uncertainty regarding the continued operation and maintenance of shared assets. Ambiguity over ownership rights, residual liabilities, and transfer of operational responsibilities in such scenarios could disrupt continuity of service and create stranded asset risks.

The framework must address this scenario where the owner of a shared network asset exits the market for any reason. A statutory obligation can be created for the network owner to maintain the asset or, alternatively, a receivership mechanism should be established to ensure continuity. The framework may also specify mechanisms through which remaining licensees can acquire or manage stranded assets.

iv. **Open access and prevention of anti-competitive practices:** Section 42(1) has been proposed to be amended requiring the owner of a network to mandatorily provide non-discriminatory open access to other licensees in its area of supply. The framework must therefore operationalise the concept of "*non-discriminatory access*" with specificity, defining what constitutes discrimination in practice. Without a uniform approach, operational asymmetries could emerge, leading to potential disputes or competitive distortions in the retail supply market.

Issues like parity in maintenance timelines, fault resolution priorities, and service quality standards should be considered to be included in such a framework. The framework must include explicit monitoring mechanisms to detect and prevent anti-competitive conduct and prescribe clear penalties violations.

b. Cost-Reflectivity of Wheeling Charges

The existing tariff design does not comprehensively ensure that all costs borne by distribution companies are reflected in the applicable tariffs. Additionally, as noted in earlier sections (Section 2.6, Section 2.8 and Section 3.3), existing tariff design is not truly cost-reflective. Even the wheeling charges currently charged by discoms do not fully reflect or even cover the true costs borne by network owners for providing their services.

This concern is particularly acute under the proposed amendment to Section 42(1) that mandates non-discriminatory open access, where competing licensees will access the network upon payment of only wheeling charges. If wheeling charges do not accurately reflect and cover the costs of a network owner's services, the network owner risks operating at a loss while simultaneously losing a share of its existing consumer base to competing licensees.

This creates a perverse incentive structure that may discourage network development and investment, hurting the entire sector and consumers in the long run. In the short term, it hurts the public discoms which currently own, operate and augment almost all the existing network which has been funded by consumer tariffs.

c. Consumer Protection and Dispute Resolution

The introduction of multiple licensees in a single supply area introduces complexities that require robust consumer protection mechanisms. When multiple licensees serve the same area, consumers may face ambiguities regarding their rights and obligations, particularly in scenarios involving bill disputes, service failures, or transitions between service providers. The framework must establish a unified and transparent grievance redressal mechanism capable of addressing disputes that arise when multiple licensees operate on a shared network. Additionally, the framework should clarify consumer protections during transitions between licensees, including protections against service disruption, clarity on liability for accumulated dues, and procedures for transfer of consumer accounts. These provisions are essential to prevent consumer exploitation under the garb of competition.

d. Regulatory Capacity and Uniformity Concerns

In some instances, state commissions may face constraints in comprehensively drafting governance frameworks for issuing multiple licences for operation in the same area. Even where commissions possess the technical capacity to undertake this task, the absence of baseline standards or guidelines may result in significantly varying frameworks across states. Such variation will create administrative burdens for entities considering multi-state operations and may discourage new entrants from participating in the sector.

In view of the above, it is imperative that the Bill outline at least the guiding principles and essential elements to be incorporated within the framework to be issued by the state commissions. Without such baseline clarity, the implementation of the proposed amendment could lead to fragmented regulation, operational inconsistencies, and potential inequities among licensees and consumers. The framework must, therefore, be comprehensive, ensuring that issues of energy accounting, cost attribution, asset management, open access, consumer protection, and regulatory uniformity are addressed in an integrated and coherent manner. Further, the establishment of an independent Distribution System Operator, as proposed, would serve as a critical institutional safeguard for operational neutrality and system reliability in a multi-licensee environment.

3.4.4. Implications for Public Discoms

Allowing multiple licensees to operate on a shared network carries serious financial and structural implications for public discoms, which currently own and maintain most distribution assets. Under the proposed framework, they would be required to provide non-discriminatory network access to new entrants without a cost-reflective mechanism to recover operational and capital expenses.

Private licensees would naturally concentrate on high-demand, low-risk urban and industrial segments, leaving the financially stressed public discoms responsible for rural, agricultural and low-income consumers who already suffer from poor and unreliable supply. As tariff design does not reflect true costs, and wheeling charges fail to compensate adequately, tariffs for residual consumers would rise, deepening affordability concerns. This effect runs contrary to the intent of Sections 61 and 86 of the Act, which mandate tariff rationality, protection of consumer interests, and universal access.

3.4.5. Recommendations on Multiple Licensees on a Shared Network

Institutional safeguards, particularly the establishment of a neutral DSO and a uniform, clearly defined regulatory structure, are essential to ensure that competition coexists with equity, consumer protection, and universal access within a multi-licensee distribution framework.

It is therefore recommended that the proposed amendment to Section 14 and Section 41(1) be supplemented with explicit provisions mandating the creation of an independent Distribution System Operator (DSO) and the formulation of a comprehensive regulatory framework by the state commissions. The DSO should function as a neutral entity responsible for system coordination, energy accounting, network planning, and ensuring non-discriminatory access to all licensees. The framework must also define the obligations and cost-recovery entitlements of the incumbent public discoms that own and maintain the distribution network, to prevent cost-shifting and safeguard their financial viability.

Further, the regulatory framework should establish transparent methodologies for cost attribution, infrastructure augmentation, and tariff setting, alongside robust mechanisms for consumer protection and dispute resolution. It must ensure that the charges for providing access to network and network access arrangements are cost-reflective and that the burden of maintaining universal service does not fall disproportionately on public discoms.

3.5. Universal Supply Obligation and Supplier of Last Resort (Section 43)

The proposed amendment to Section 43 of the Act introduces a provision allowing state commissions, in consultation with State Governments, to exempt distribution licensees from the obligation to supply electricity to consumers whose demand exceeds one megawatt. It also empowers the Commission to designate another licensee to assume supply responsibilities where an existing arrangement fails, creating a de facto "*Supplier of Last Resort*" (SoLR) mechanism. While the amendment seeks to enhance supply flexibility, its design introduces structural and financial asymmetries that are inconsistent with the operational realities of India's distribution sector and the statutory principles enshrined under Sections 61 and 86 of the Act.

3.5.1. Structural Asymmetry and Unequal Obligations

The amendment establishes a fundamental imbalance between exempted licensees and the designated SoLR. Exempted licensees may choose not to serve consumers above 1 MW demand, thereby avoiding high-volume consumers who account for a substantial share of area-wide demand but are likely to be self-supplied through captive sources. These licensees can therefore restrict their operations to smaller consumer segments and align their procurement portfolios to lower and more predictable loads.

By contrast, the SoLR, most plausibly the public discoms that already own and operate the vast portion of existing network infrastructure, must maintain the capacity to serve all consumers in the area, including those above one megawatt, regardless of whether it derives revenue from them under normal conditions. Moreover, the reliability requirements of such high-demand consumers are substantially greater in both technical and capacity terms. The SoLR must therefore maintain additional reserve margins, network redundancy, and higher-quality supply parameters to meet these expectations.

Consequently, the SoLR functions as a perpetual standby supplier, bearing universal service obligations without reciprocal revenue flows or compensatory mechanisms. It cannot refuse designation or decline any consumer segment, whereas exempted licensees can selectively exclude high-cost or high-risk categories. This asymmetry undermines competitive neutrality. In established electricity markets such as the United Kingdom, the European Union, and Australia, SoLR designation is either voluntary or awarded through competitive bidding, with compensation provided via industry-wide levies, reliability charges embedded in tariffs, or regulated reimbursement. If the proposed framework in the Bill envisages or results in a scenario where the SoLR does not have a say in its designation, the framework must at least incorporate a compensatory mechanism such as a Reliability Reserve Charge (RRC) or pooled compensation arrangement to preserve the financial and operational viability of SoLRs.

3.5.2. Financial Incompatibility in a PPA-Dominated Sector

India's distribution sector is characterised by long-term Power Purchase Agreements (PPAs) with substantial fixed capacity charges. A significant portion of power procurement costs for discoms arises from these charges, which must be paid irrespective of electricity offtake.

For the SoLR, this creates a structurally untenable financial position. To remain ready to serve all consumers in its area, including those with high demand and captive supply, the SoLR must contract capacity for the entire area demand. Yet, in practice, its revenue is confined to a smaller subset of consumers that it continues to supply. The result is a mismatch between fixed procurement obligations and realised revenue. The financial consequences are severe:

a. **Unrecoverable fixed costs:** Capacity-related charges accumulate continuously, even when the SOLR supplies little or no power to exempted consumers.
b. **Stranded capacity:** The SoLR must maintain standby assets for demand segments that may never return to its supply, with higher infrastructure costs due to elevated reliability requirements.
c. **Working capital lock-up:** The SoLR must maintain credit lines for PPAs and maintain the assets without corresponding cash inflows.
d. **Cost-recovery paradox:** If the Commission allows recovery through a separate tariff, rates become prohibitively high; if excluded, the SoLR operates at a loss.

Given that public discoms (which may inevitably be designated as SoLRs) are already financially constrained, this structure risks stressing their finances further, and render them incapable of meeting both USO and SoLR responsibilities simultaneously.

3.5.3. Cost-Reflective Tariff Paradox

The proposed framework conflicts directly with the Electricity Act's guiding tariff principles which mandate tariff rationality and ensure recovery of reasonable costs while safeguarding consumer interests. Section 86 requires commissions to ensure that tariffs promote efficiency, economy, and equitable consumer treatment.

Under the proposed SoLR mechanism, it has not been specified how "cost-reflective" tariffs can be determined. The SoLR's standby costs, comprising capacity charges, financing costs, and maintenance of unutilised infrastructure, cannot be recovered through conventional tariff design without breaching fairness principles as they socialise costs across consumers and operations. Conversely, excluding these costs renders the SoLR's operations unsustainable. The resulting distortion thus undermines cost-reflectivity and produces a tariff design that may either be inequitable or economically unviable.

3.5.4. Conclusion and Recommendations

The proposed exemption under Section 43 and the creation of a SoLR framework, while intended to promote flexibility and competition, risk displacing the principles of tariff rationality, USO and consumer protection enshrined in Electricity Act. In absence of explicit recovery mechanisms, public utilities, which will inevitably be SoLRs, would suffer from the fiscal and operational burden of reliability for all consumers, while reducing their revenue.

It is therefore recommended that the Bill proposes a framework mandating regulations for ensuring SoLR's cost recovery. These can be ensured through levy of a reliability and SoLR surcharge on the large consumers or be through a pooled fund from all open access consumers which will compensate the SoLRs for their losses in their role as SoLR.

3.6. Independence and Removal of State Commission Members (Section 90)

The proposed amendment to Section 90 of the Electricity Act introduces substantive alterations to the provisions governing the removal and suspension of members of the State Electricity Regulatory Commissions (SERCs). It expands the grounds for removal to include "wilful violation" and "gross negligence" and empowers the Central and other state governments to initiate such proceedings. Additionally, the amendment permits suspension of members pending inquiry, following only a consultative process with the Chairperson of the Appellate Tribunal for Electricity (APTEL). These changes collectively alter the balance of institutional autonomy envisaged under the existing framework, which sought to insulate regulators from political and executive influence. Some of these challenges are deliberated upon hereunder.

3.6.1. Risks to Institutional Autonomy

The independence of state commissions forms the cornerstone of rational, evidence-based decision-making in the electricity sector. By enabling the Central and state governments to initiate the removal of state ERC members, the proposed amendment undermines this independence. The inclusion of ambiguous grounds such as "*wilful violation*" and "*gross negligence*" introduces subjectivity that may permit politically motivated interpretations.

In effect, decisions adverse to governmental or commercial interests such as tariff determinations, penalty impositions, or disallowance of imprudent expenditure could expose members to retaliatory proceedings. The coercive oversight through removal or suspension powers compromises regulatory neutrality and risks discouraging the regulators from taking hard but necessary decisions.

In the long run, it weakens the credibility of decisions rendered by state commissions. Over time, such a regime risks diminishing public confidence in regulatory processes, reducing investor predictability and erosion of the sector's institutional integrity.

3.6.2. Procedural and Federal Infirmities

The proposed procedure for suspension under Section 90(3) allows members to be relieved of their duties without a preliminary inquiry or the establishment of *prima facie* evidence. The only safeguard accorded in 90(3), that is consultation with the Chairperson of APTEL, is not binding and therefore inadequate to prevent arbitrariness. Such a framework contravenes principles of natural justice and erodes due process protection necessary for independent adjudication.

3.6.3. Distortion of Federal Balance

The extension of authority to the Central Government and to other State Governments to initiate or recommend removal of members distorts the federal balance embedded within the Electricity Act. State ERCs are anchored as state-level quasi-judicial bodies, meant to operate autonomously within their jurisdiction. Any mechanism that enables external executive influence, particularly from the Centre or from other states, conflicts with this structure and threatens to centralise regulatory control in contravention of the Act's decentralised design.

3.6.4. Conclusion and Recommendations

The proposed amendment to Section 90 poses a fundamental threat to the independence and credibility of India's electricity regulatory architecture. The introduction of vague removal grounds, coupled with expanded executive discretion and weakened procedural safeguards, compromises both due process and federal balance.

To preserve the autonomy and accountability of State Commissions, the following measures are essential:

- **a.** The terms "wilful violation" and "gross negligence" must be explicitly defined through objective statutory or regulatory criteria to prevent arbitrary invocation.
- **b.** Suspension should be contingent upon a preliminary inquiry establishing prima facie evidence of misconduct, and consultation with APTEL should be mandatory and binding.
- **c.** The powers of the Central and other State Governments to initiate or recommend removal of SERC members should be curtailed or conditioned upon independent review by a neutral committee constituted for this purpose.
- **d.** APTEL's role should be strengthened to act as the final and independent arbiter in disciplinary matters concerning SERC members.

Only by ensuring such procedural safeguards can the Electricity Act continue to uphold the regulatory independence envisioned by the legislature.

3.7. Accountability and Procedural Discipline in Regulatory Adjudication (Section 92)

Under Section 92(6), the Bill proposed the addition of a timeline for adjudicatory proceedings, which is a welcome step toward improving efficiency. However, limiting the requirement to merely recording reasons for delay does not address the root causes of procedural bottlenecks. Delays in proceedings often arise from incomplete or inadequate submissions by petitioners, licensees, or other parties, rather than merely from the Commission's inaction.

To address this, the Act should require the Appropriate Commission to identify the party or parties responsible for such delays in each proceeding. Where the delay is attributable to non-submission of information, repeated revisions, or administrative laxity by any utility or parties, the Commission should exercise its powers under Section 142 to impose penalties. In cases where such penalties are deemed unnecessary, the Commission should be required to provide clear reasons for not invoking its enforcement powers.

Further, the Commission should be mandated to establish a framework governing the manner and completeness of petition filings. At present, tariff and adjudicatory filings often lack essential data, leading to repeated queries and resubmissions that significantly prolong the process. For example, in Rajasthan, the commission, through multiple orders, has highlighted instances of petitions being filed with severe data gaps, illegible documents and datasets, which restrict meaningful scrutiny by the Commission and stakeholders and contribute to procedural delays. A standardised filing framework specifying formats, mandatory information, and supporting documents would ensure procedural discipline and shorten the overall timeline for disposal of cases.

3.8. Data Discipline for Effective Suo Motu Tariff Determination (Section 64(1))

Under Section 64(1), the Bill proposes an amendment that rightly empowers the Appropriate Commission to determine a tariff *suo motu* in cases where a utility fails to file its tariff petition within the prescribed timeframe. However, for such a provision to be effective, it must be supported by a mandatory framework for regular reporting of data submission by the utilities. In the absence of a reliable and updated financial and operational report, a *suo motu* tariff determination would be an administrative formality rather than a substantive exercise in regulatory oversight.

We suggest that the Act direct and empower the state commission to mandate all parties covered under Section 62 to submit quarterly operational and financial performance reports to the Commission. Such periodic filings would enable the Commission to maintain an updated database, facilitating timely and evidence-based *suo motu* tariff determination when required.

Further, the Commission should be required to seek reasons from the utility for any delay in filing its tariff petition within the stipulated time. If such a delay is found to be without reasonable justification or attributable to administrative laxity, the Commission should exercise its powers under Section 142 and impose penalties on responsible persons within the party. This would reinforce regulatory discipline and ensure that tariff petitions are filed in a timely and transparent manner.

3.9. Electricity Council and Safeguarding Regulatory Independence (Section 166(1A))

The Bill, under Section 166(1A), proposes the establishment of an Electricity Council, which aims to strengthen Centre–State coordination and facilitate consensus on policy reforms. While this intent aligns with the goal of cooperative federalism, its institutional positioning raises concerns on independence of regulator. The power sector already operates through several formal coordination mechanisms: the Forum of Regulators for policy harmonisation, Coordination Forums at the Central and State levels for system planning, and the Central Electricity Authority for technical and operational standards. Introducing another policy-tier body without a clearly delimited mandate risks duplicating functions already embedded in the regulatory and technical architecture of the Act.

3.9.1. Institutional Risk and Rationale for Caution

The Electricity Act, 2003, was created to establish independent regulatory regime, precisely to insulate tariff determination and market oversight from political or short-term considerations. These institutions were intended to act as the neutral interface between the legislature, the executive, and market participants, ensuring decisions grounded in evidence and consumer interest. A high-level council chaired by the political executive, even if formally advisory, may in practice exert influence that Commissions perceive as binding. Such soft direction can erode regulatory autonomy and create confusion.

Regulatory commissions are already subject to public accountability and appellate scrutiny. Adding an additional policy forum above them may inadvertently subordinate long-term, evidence-based regulation to short-term administrative consensus, weakening the institutional balance that the Act was designed to protect.

The Electricity Council, if retained, should therefore be confined to functions that genuinely require executive coordination rather than regulatory discretion. Its role may be limited to broad policy alignment, scheme funding, implementation oversight, and capacity-building initiatives between the Centre and States. The Council's advice should remain explicitly non-binding and should not be construed as directions to the regulatory institutions.

We therefore recommend that the scope of the proposed Electricity Council be limited to coordination and implementation of schemes, and high-level policy convergence, without extending into matters under the statutory domain of regulatory or technical bodies. This would preserve the independence and credibility of the regulatory framework while advancing the cooperative federalism that the amendment rightly seeks to promote.

3.10. Rule-Making Powers of the Central Government (Section 176)

The proposed amendment to Section 176(1) replaces the existing phrase *"for carrying out the provisions of this Act"* with *"for carrying out the purposes of this Act"*. This revision significantly raises the following concerns:

3.10.1. Expansion of Scope through "*Purposes*"

The term *"purposes"* is inherently open-ended and creates interpretive ambiguity. Under the current framework, the Central Government can frame rules only with respect to identified provisions of the Act and specifically on matters laid down in under Section 176(2), ensuring a clear legislative boundary. By contrast, "*purposes*" grants rule-making power that is not confined to specific statutory mandates, potentially authorising rules on matters that the Act initially did not intend to delegate. This change represents a substantive shift from targeted rule-making to a general enabling power, with no reasonable explanation or justification, corresponding safeguards or definition of "*purposes*" to limit its ambit.

3.10.2. Risks of Overreach and Centralisation

This broadened authority risks upsetting the federal balance envisaged in the Electricity Act, 2003. Rule-making powers are presently clearly demarcated between the Centre, the states, the regulatory commissions and the CEA. Allowing the Centre to make rules for undefined "*purposes*" could authorise intervention even in areas reserved for other bodies in the Act, thereby eroding their autonomy.

Additionally, such an overarching delegation weakens procedural accountability. The absence of defined limits expands the executive's discretion without corresponding legislative scrutiny, concentrating authority at the Centre and creating scope for political or administrative overreach inconsistent with the Act's institutional design.

3.10.3. Conclusions and Recommendations

The existing wording *"for carrying out the provisions of this Act"* should be retained. If the amendment is pursued, it must be narrowly framed, for example, *"for carrying out the specific provisions and objects expressly stated in this Act."* Further, any expansion of rule-making powers should be accompanied by procedural safeguards such as prior consent of state governments and sectoral bodies, mandatory publication and stakeholder review. These measures would preserve legislative intent while ensuring transparency and accountability in delegated legislation.

3.11. National Performance Standards for Equitable Compliance (Section 58)

The proposed amendment Bill empowers the Central Government to set minimum standards of service applicable to all States. It is hereby submitted that service conditions (such as reliability, voltage stability, and supply hours) vary significantly between urban and rural networks and across States. For instance, rural areas in Rajasthan or Jharkhand cannot easily meet Delhi-level reliability benchmarks. Therefore, the prescribed benchmarks should be realistic and account for contextual variations rather than being uniform across all entities.

It is recommended that minimum service standards be developed by the Central Government in consultation with the Forum of Regulators (FoR), the Central Electricity Authority (CEA), and State Commissions, ensuring consensus and state-level adaptability. These standards may be jointly reviewed by the same authorities to assess progress and revised periodically, balancing consumer interests with the viability of the distribution sector.

Beyond the setting of such benchmarks, the implementation of these standards by utilities and the timely disbursal of compensation in cases of non-compliance remain major challenges. It is therefore suggested to mandate the development of a framework by SERCs to ensure state-specific implementation of standards, supported by periodic reviews and capacity-building measures.

3.12. Security Oversight in Defence-Related Clearances (Section 15 and Section 18)

The Bill proposes the deletion of Sections 15 (2) (ii) and 18 (2) (b), which removes the statutory requirement for obtaining no-objection clearance from the Central Government in cases where a licence area covers cantonments, aerodromes, dockyards, or other defence establishments. These provisions were introduced to safeguard national-security interests in the licensing process, ensuring that electricity infrastructure development did not conflict with the operational or spatial requirements of defence installations. Their deletion, therefore, raises important questions of institutional oversight and procedural clarity.

We seek clarification on the procedure and administrations responsible for issuing such no-objection certificates (NOCs). While the statutory language refers broadly to the "Central Government," the actual clearance may rest with specific entities such as the Ministry of Defence, the Directorate General of Defence Estates, or other designated bodies. Deletion of these provisions without defining an alternative institutional process could therefore lead to procedural uncertainty and potential oversight in matters involving defence installations.

Moreover, the no-objection certificate is a one-time clearance valid generally for the long-term licence period**,** and hence does not impose a recurring compliance burden. The earlier safeguard, therefore, cannot reasonably be viewed as an impediment to ease of doing business. Instead, the concern lies in the absence of a time-bound process at the government end, which may result in procedural delays.

We therefore recommend that, instead of deleting these clauses, the Central Government consider streamlining and time-bounding the NOC process at its end. A clear mechanism specifying the responsible authority and a defined timeline for issuing defence clearances would preserve security oversight while ensuring procedural efficiency for applicants. This approach would balance both objectives — operational efficiency and national security without compromising either.

3.13. Non-Fossil Sources Purchase Obligations (Section 86(1)(e))

The proposed amendment to Section 86(1)(e) introduces two major changes — replacing the term *"renewable sources"* with *"non-fossil sources"* and empowering the Central Government to prescribe the percentage of electricity consumption to be procured from such sources. This shift reflects a move towards centralisation of a concurrent subject, potentially undermining the functional autonomy of State Electricity Regulatory Commissions (SERCs).

The term *"non-fossil sources"* expands the scope of obligation to include nuclear and green hydrogen-based generation in addition to conventional renewables. However, green hydrogen technology is commercially and technically nascent. As of 2025, India's installed nuclear capacity is about 8,880 MW[8], while green hydrogen-based electricity is still under pilot-scale development without any defined cost framework.

3.13.1. Conclusions and Recommendations

In the absence of clear pricing and fuel linkage mechanisms, imposing non-fossil obligations may result in higher procurement costs and compliance difficulties for Discoms.

It is therefore recommended that the Bill include a cost-effective and phased implementation framework for non-fossil obligations, developed in consultation with stakeholders. The framework should provide for periodic review, consider regional resource availability, and

[8] https://www.pib.gov.in/PressReleasePage.aspx?PRID=2118374

ensure that state-level obligations remain economically viable and consistent with national decarbonisation objectives.

3.14. Market-Linked Penalty for Non-Fossil Compliance (Section 142(2))

The Bill, under Section 142(2), proposes the introduction of a penalty for non-compliance with non-fossil energy obligations under Section 86(1)(e), which addresses an important enforcement gap in the Act. However, prescribing a static penalty range computed based on market price (₹0.35 – ₹0.45 per kilowatt-hour) may undermine the very purpose of the amendment. The cost of renewable energy and the price of Renewable Energy Certificates (RECs) are both market-dependent and may fluctuate in response to supply, technology costs, and trading dynamics.

A static penalty would eventually lose its deterrent value as REC or non-fossil market prices change, and may even anchor the value of non-fossil attributes, distorting market behaviour. Experience from the REC market shows that static ceilings tend to suppress price discovery and weaken compliance incentives. If the statutory penalty is lower than the cost of compliance, obligated entities are likely to treat it as a routine financial cost rather than a deterrent, weakening the effectiveness of the obligation. The intent of the amendment to promote genuine renewable procurement rather than penalty payment can only be achieved through a market-responsive penalty mechanism.

3.14.1. Comments and Suggestions

We therefore suggest that the Act specify a dynamic, market-linked penalty framework, wherein the rate is determined at the time of imposition, according to the actual market price of RECs or renewable energy, with an added premium on the current market price to preserve deterrence. The premium could be expressed as a fixed percentage above the average market price observed over the previous quarter or year. Such a framework would better reflect the principles of deterrence and regulatory consistency, ensuring that the enforcement mechanism evolves in tandem with the non-fossil energy market.

3.15. Electricity Line Authority (Section 164)

3.15.1. Definition of 'Electric Line Authority' under Section 2(20a)

Section 2(20a) defines the Electric Line Authority in line with the Bill's objective of transferring the powers of the erstwhile Telegraph Authority to the newly established Electric Line Authority. The Section defines the Authority as a person authorised to undertake the functions of the *Electrical Line Authority* under the Act.

The powers of this Authority are provided under Section 164 of the Bill. A plain reading of this provision, and indeed of the entire Bill, shows that only the term ***Electric** Line Authority* has been used throughout. The term ***Electrical** Line Authority*, appearing in the definition under Section 2(20a), is not used in Section 164.

Unless the Bill intends to establish two distinct authorities performing separate functions, the inconsistent use of two synonymous but separate terms for the same entity creates ambiguity in interpretation and implementation.

It is therefore recommended that the term *'Electrical Line Authority'* in Section 2(20a) be replaced with *'Electric Line Authority'* to ensure consistency and avoid interpretational uncertainty across the Bill.

3.15.2. Undefined Scope of '*As Little Damage as Possible*'

Under the proposed Section 164(2), clause (d) empowers the Electric Line Authority to cause "*as little damage as possible*" while exercising its powers, and mandates payment of full compensation to all affected persons for any damage sustained to property other than that referred to in clause (c). The clause specifically states:

"In the exercise of the powers conferred by this sub-section, the Electric Line Authority shall do as little damage as possible, and, when it has exercised those powers in respect of any property other than that referred to in clause (c), shall pay full compensation to all persons interested for any damage sustained by them by reason of the exercise of those powers."

However, the Bill neither defines nor elaborates upon the phrase *"as little damage as possible"* with reference to any existing legal framework, standards, or rules. Moreover, it does not confer any oversight or regulatory power upon the appropriate government to ensure minimisation of such damage. This lack of clarity renders the clause vague and subjective in nature. To ensure transparency and accountability, it is imperative that the Bill specify clear guidelines, assessment criteria, and monitoring mechanisms for determining and enforcing the obligation to minimise damage.

3.15.3. Mandatory Framework for Laying of Electric Lines

Under the proposed Section 164(2), clause (e) provides that *"The State Government may prescribe a framework to facilitate the placing of electric lines, including determination of compensation to be paid."*

The use of the term *"may"* in this clause merely grants discretionary power to the State Government to frame such a framework, thereby allowing relaxation in its implementation. However, this framework is crucial to avoid ambiguity and potential disputes between the public and the Electricity Line Authority, which may otherwise lead to delays or non-execution of works.

It is therefore recommended that the word *"may"* be substituted with *"shall"* to make it a mandatory obligation for the State Government to prescribe such a framework. Furthermore, the clause should explicitly require periodic revision of the framework and the compensation mechanism in consultation with relevant stakeholders to ensure transparency, fairness, and effective implementation.

****End of Submissions****