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भारत सरकार

विद्युत मंत्रालय

केन्द्रीय विद्युत प्राधिकरण

वित्तीय एवं वाणिज्यिक मूल्यांकन प्रभाग

*****

Sewa Bhawan, New Delhi-66

दिनांक: 23.12.2025

विषय: - विद्युत प्रणाली के विभिन्न खंडों में लागत में कमी के दायरे पर बैठक - रेग। (Report on Scope of Cost Reduction in various segments of the Power System – reg.)

The undersigned is directed to state that the Ministry of Power, vide letter No. 13/6/2019-OM dated 17.07.2025(attached), has requested CEA to conduct a study/analysis on the scope of cost reduction in various segments of the power system—generation, transmission, and distribution.

2. To ensure a comprehensive and balanced analysis, a series of stakeholder consultations were organized to solicit diverse inputs on the subject. These meetings involved discussion with representatives from generation companies, transmission utilities, distribution companies, as well as expert organizations such as Prayas (Energy Group) and The Energy and Resources Institute (TERI), on 20.08.2025, 08.09.2025 and 03.11.2025

3. Based on inputs received from stakeholders, a report on the scope of cost reduction in various segments of the power system—generation, transmission, and distribution has been prepared and the same is enclosed.

4. This issues with the approval of Chairperson, CEA.

Encl: as above

Mrityunjay 23/12/2025

(Mrityunjay Varshney)

Deputy Director(F&CA)

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To:

Additional Secretary (OM), Ministry of Power, New Delhi

Copy to:

Director (IT), CEA – with a request to upload in CEA website

Report on the "Scope of Cost Reduction in Power System Generation, Transmission and Distribution"

F&CA Division, CEA

December 2025

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Executive Summary

India's power sector has achieved remarkable milestones—universal household electrification, integration into a single national grid, and rapid renewable energy growth—while maintaining one of the lowest household electricity prices globally (~0.08 USD/kWh). However, the Average Cost of Supply (ACoS) varies widely across states, driven predominantly by power purchase costs (70–80% of ARR), transmission charges, and O&M expenses. With electricity demand projected to grow significantly towards 2047, reducing system costs is essential to minimise the tariff burden on consumers without compromising reliability or the transition to cleaner energy.

This report, prepared in response to Ministry of Power directions (July 2025), identifies practical measures across generation, transmission, distribution, and regulatory/scheduling domains to introduce efficiencies, remove distortions, and lower consumer tariffs. The recommendations emerged from extensive stakeholder consultations with generation companies, transmission and distribution utilities, and expert organisations including Prayas (Energy Group), TERI, APP, and NTPC.

Key Findings and Potential Tariff Reduction Opportunities

1. **Generation:** Thermal power continues to dominate (74.5% of generation in 2024-25), making cost reduction in coal-based generation critical. Major opportunities include:
    - Addressing coal grade slippage through automated sampling and Total Moisture Basis measurement (potential ~18 paisa/kWh savings).
    - Rationalising state-level taxes, royalties, cess, mine-specific charges, performance incentives, and bridge-linkage premiums (cumulative 50–150 paisa/kWh in affected stations).
    - Phasing out railway freight cross-subsidy and rationalising short-distance rates (10–15 paisa/kWh average).
    - Hydro and renewable costs can be reduced through streamlined clearances, back-loading of tariffs, lower free power obligations, SGST waivers, cheaper finance, and targeted GST reductions (combined potential 50–150 paisa/kWh for new projects). Energy storage costs can be lowered via reduced GST on leasing and expanded Viability Gap Funding.
2. **Transmission:** Despite massive grid expansion, utilisation remains low (<30%). Recommendations focus on:
    - Enhancing utilisation through Energy Storage Systems and Dynamic Line Rating (10–25 paisa/kWh).
    - Mandating Tariff-Based Competitive Bidding for all new systems (30–40% cost reduction observed in ISTS).
    - Promoting load centres near generation hubs and distributed RE to minimise long-distance transmission needs.
    - Continued budgetary support for RE evacuation while reviewing waivers (e.g., for green hydrogen).

3. **Distribution:** High AT&C losses (national average 16.16%), accumulated losses (₹7.08 lakh crore), and regulatory delays drive cost escalation. Key measures include:
    - Reducing AT&C losses to single digits (6 paisa/kWh per 1% reduction).
    - Restructuring DISCOM debt (potential ~9 paisa/kWh at 2% interest reduction).
    - Ensuring timely tariff orders and liquidation of regulatory assets.
    - Redesigning tariffs for proper fixed-cost recovery, implementing Time-of-Day tariffs with solar-hour rebates, promoting prepaid metering, and stabilising fuel surcharges.
4. **Regulatory & Scheduling Aspects:** Efficiency gains can be realised through:
    - Security Constrained Economic Dispatch at intra-state level (2–3% savings, ~₹10,000 crore annually).
    - Higher debt-equity norms, shorter PPA durations, short-term capacity reallocation, and demand-response programmes.

Conclusion

Implementation of these recommendations—many requiring coordinated action between Central and State Governments, regulators, coal companies, railways, and utilities—offers substantial scope for tariff reduction ranging from a few paisa to over a rupee per unit in aggregate, depending on the segment and extent of adoption. Prioritising high-impact, low-cost controversy measures (e.g., improved coal sampling, transmission bidding, AT&C loss reduction, and SCED) can deliver quick wins, while structural reforms (tax rationalisation, tariff redesign) will yield sustained benefits. An annual review mechanism, as envisaged by the Ministry, will help track progress and refine approaches for a more efficient and consumer-friendly power sector.

Chapter 1: Introduction

1.0 Background

Ministry of Power vide letter no. 13/6/2019-OM dated 17.07.2025 conveyed the directions to carry out detailed study on Scope of cost reduction in various segments of power system including generation, transmission, and distribution. It was also decided that this can be an annual exercise and will help in reducing in tariff burden of consumers

To ensure a comprehensive and balanced analysis, a series of stakeholder consultations were organized to solicit diverse inputs on the subject. These meetings involved discussion with representatives from generation companies, transmission utilities, distribution companies, as well as expert organizations such as Prayas (Energy Group) and The Energy and Resources Institute (TERI), on 20.08.2025, 08.09.2025 and 03.11.2025. The study also drew upon the insights from the Forum of Regulators' 2021 report titled "Analysis of Factors Impacting Retail Tariff and Measures to Address Them." A holistic review of all factors influencing consumer tariffs was undertaken, incorporating valuable contributions from key entities including the Association of Power Producers (APP), Prayas (Energy Group), MB Power, NTPC Ltd, The Energy and Resources Institute (TERI), PSETD Division of CEA, and DP&T Division of CEA. The key findings from this exercise, along with proposed pathways for implementation, are elaborated in the subsequent sections of this report.

2.0 Indian Power Sector at a glance

India's power sector is one of the largest and fastest evolving energy system globally, characterized by substantial growth in generation, transmission, and renewable energy capacity in recent years. It is central to the country's economic development and faces both rapid modernization and ongoing challenges. The sector comprises public and private utilities, with electricity generation, transmission, and distribution managed through a combination of central, state, and private sector involvement. Central, state, and private entities play key roles, with the private sector holding the largest share in generation capacity (over 50%) as of mid-2023. Coal remains the backbone of Indian power generation, though rapid increases in solar and wind capacity have reduced its share. Renewable energy is expanding quickly, with installed solar capacity nearly doubling to over 100 GW in the last two years and government targets demanding 500 GW of non-fossil generation by 2030. Hydropower and wind generation capacities remain essential components, complemented by emerging technologies such as pumped hydro storage and battery systems.

2.1. All segments within the power sector such as generation, transmission and distribution have witnessed transformational changes since 2005. The Electricity Act, 2003, NEP and Tariff policies have facilitated the improvement in the power sector performance. Delicensing of generation and its opening to the private sector have significantly advanced the growth of the power sector. This initiative has attracted substantial investments in generation, resulting in adequate generation capacity within the country. India has successfully achieved universal access to electricity, connecting all villages and households nationwide.

2.2. The integration of regional grids into a single national grid, effective from 31.12.2013, has enabled the free flow of power from surplus regions to deficit areas via robust inter-regional AC and HVDC links. This has led to remarkable improvements in performance metrics, such as reductions in unmet peak demand (in MW) and energy shortages (in MU) on an all-India basis.

2.3. Statistical comparison for some key power sector indicators are given as under:

2.3.1 Installed Capacity

Type	Installed Capacity (MW) (as on 31.03.2005)	Installed Capacity (MW) (as on31.08.2025)
Thermal	80902	244139
Hydro	30936	50108
Nuclear	2770	8780
Wind	2980	52681
Solar		123130
Other RES	831	16706
Total	118419	495545

2.3.2 Power Supply Position

<u>**Energy**</u>

Year	Requirement (Billion Unit)	Availability (Billion Unit)	Shortage (Billion Unit)	Shortage (%)
2004-05	591.373	548.115	43.258	7.3
2024-25	1693.959	1692.369	1.590	0.1

<u>**Peak Demand**</u>

Year	Peak Demand (GW)	Peak Demand Met (GW)	Shortage (GW)	Shortage (%)
2004-05	87.906	77.652	10.254	11.7
2024-25	249.856	249.854	2	0

2.4 Transmission Capacity

Year	Transmission Line Length (ckm)	Transformation Capacity (MVA)	Inter-regional Capacity (MW)
31.03.2005	1.60 lakh	2.25 lakh	9,550
30.09.2025	4.96 lakh	13.82lakh	1,20,340

2.5 Per Capita Electricity Consumption

	2004-05	2023-24
Per Capita Consumption (kWh)	612	1395

3.0 Future projections

With greater electrification of the energy demand, going forward, the estimated capacity mix in 2046-47 is estimated as follows:

Installed Capacity (GW)			
Type	**(as on 31.03.2025)**	**Estimated in 2029-30**	**Estimated in 2046-47**
Thermal	**247**	**277**	**250**
Hydro	**48**	**78**	**98**
Nuclear	**8**	**15**	**54**
Wind	**50**	**100**	**436**
Solar	**106**	**293**	**1191**
Other RES	**16**	**14**	**23**
Total	**475**	**777**	**2052**

Estimated peak and energy requirements are estimated as follows:

Power Demand Projection			
	2024-25 (Actual)	**Estimated in 2029-30**	**Estimated in 2046-47**
Energy (BU)	**1694**	**2280**	**4582**
Peak Demand (GW)	**250**	**335**	**697**

4.0 Prevailing Cost of Supply in the country and average tariff in the country:

Average Cost of supply (ACoS) is the average cost incurred by a distribution licensee to supply one unit of electricity at its consumer's metering point[1]. ACoS forms the basis for the determination of retail tariff by the appropriate Electricity Regulatory Commission for different types of consumers (domestic/consumer/industrial/commercial/agriculture).

As per information available in PFC report on "Performance of State Power Utilities", variation of ACoS in recent years are as under[2]:-

Year	ACoS (₹/unit)
2016-17	5.38
2017-18	5.50
2018-19	6.00
2019-20	6.14
2020-21	6.19
2021-22	6.28
2022-23	7.08
2023-24	7.09

Power Purchase Cost (PPC) accounts for about 70% - 80% of Annual Revenue Requirement (ARR). Power procurement cost varies significantly across states, from as low as about Rs 2.84-2.47 per kWh in Kerala and Himachal Pradesh, to as high as Rs 8.70 per kWh in states such as Delhi. The power procurement cost is followed by transmission charges and the O&M expenses. Transmission charges contribute in the range of 9.5% - 13.5% and O&M expenses in the range of about 6% - 21%.

World-wide variation of house-hold electricity price is depicted in Figure-1. Ireland, Italy, and Germany had some of the highest household electricity prices worldwide, as of March 2025. At the time, Irish households were charged around 0.45 U.S. dollars

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[1] Definition:

[2] Report on Performance of Power Utilities. [available] https://www.pfcindia.co.in/ensite/DocumentRepository/ckfinder/files/Operations/Performance_Reports_of_State_Power_Utilities/Report%20on%20Perfromance%20of%20Power%20Utilities%202023-24(1).pdf

per kilowatt-hour, while in Italy, the price stood at 0.43 U.S. dollars per kilowatt-hour. By comparison, in India, average household prices are about 0.08 U.S. dollars per kilowatt-hour which is comparable to China.

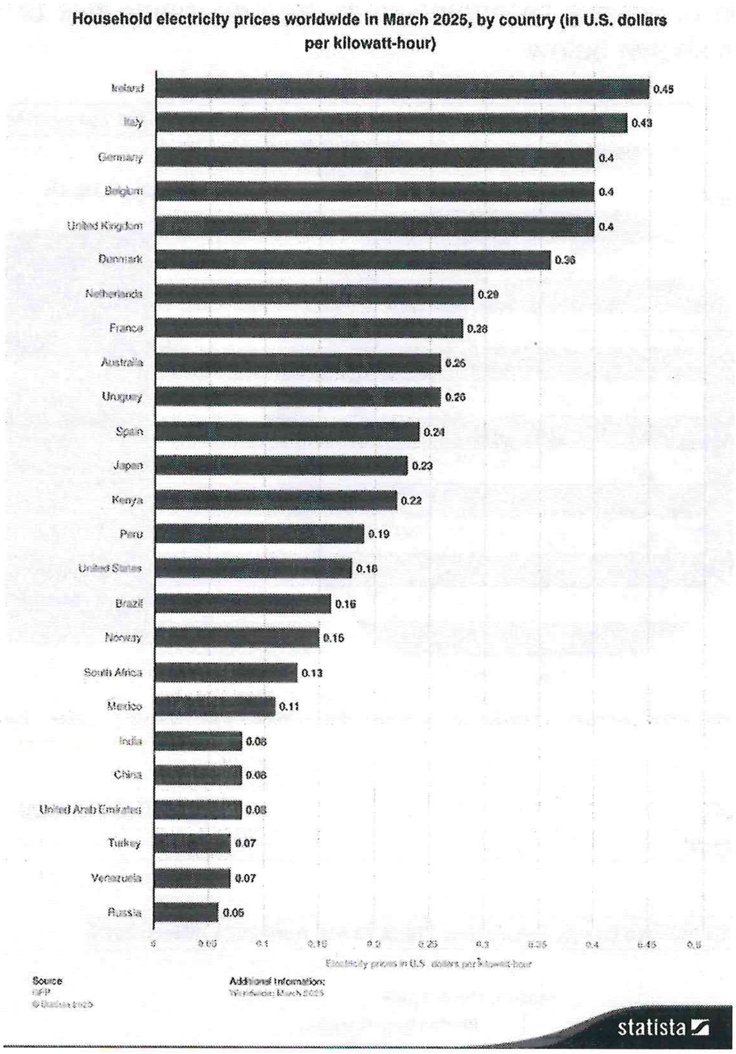


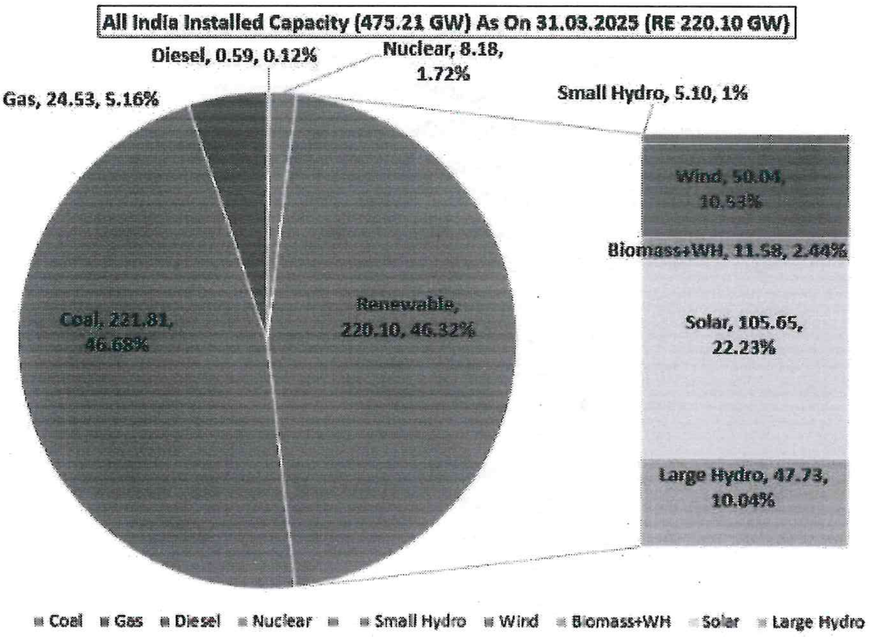
Figure1: House-hold electricity prices across the World (Source: https://www.statista.com/statistics/263492/electricity-prices-in-selected-countries)

Power Procurement Cost (PPC) is the largest contributor to the average cost of supply, having on an average more than 70% share in the cost for a distribution company. Following PPC, transmission charges and O&M Expenses have a major share. The subsequent chapters delve into the major components of the electricity sector, analyzing opportunities for introducing efficiencies and eliminating distortions to ultimately lower consumer tariffs.

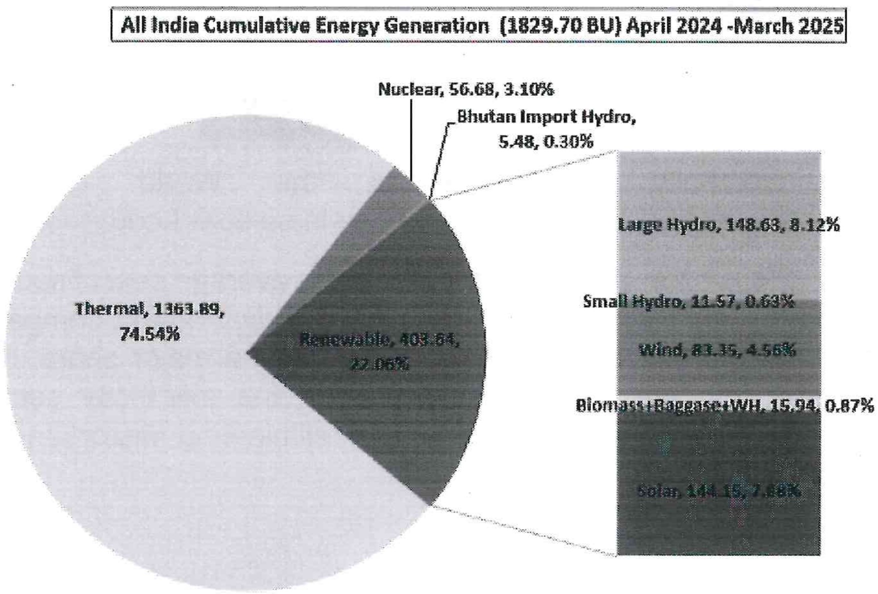
Chapter 2: Generation

1.0 Introduction

The contribution of various technologies in the generation mix of the country as on 31.03.2025 is as shown below



Further, the energy generation from various technological sources for the year 2024-25 is shown below:



2.0 Thermal Generation

Despite the accelerated addition of renewable installed capacities, thermal generating stations continue to fulfil the bulk of energy requirement, as the capacity utilization factors for renewables is much lower. In 2024-25, thermal generation contributed to 74.54% of total generation in the country. Going forward, a sizable proportion of generation would continue to be coal based to ensure energy security unless cleaner technologies such as nuclear come up in scale. Therefore, any reduction in cost of thermal generation would significantly reduce average cost of supply. Following measures could be considered to reduce cost of thermal generation in India:

2.1 Coal Grade Slippage: Grade slippage in coal refers to the situation where the actual quality of coal (especially its Gross Calorific Value or GCV) received at a plant (GCV as Received) is lower than the declared grade (GCV as billed). This slippage can have significant financial and operational impacts on power plants and consumers. At present, coal is billed as per GCV measured at loading point, and huge loss in GCV between point of coal purchase and its use result in variable cost of coal-based generation being much higher than warranted.

Average grade slippage of NTPC stations in 2024-25 was of the order of 465 kCal/kg with potential savings of Rs 6300 Crores and tariff reduction potential of 18 paisa/kWh.

The major reasons for grade slippage are as under:

a) **Methodological differences in assessing coal grade:** Analysis highlights that the one of the causes of grade slippage is methodological. While billing is assessed under specific conditions of temperature, humidity, etc for billing (Equilibrated basis), the coal actually used by the generator under prevailing conditions (Total Moisture Basis). Differences between EB (Equilibrated Basis) and TMB (Total Moisture Basis) measurements contribute to GCV loss of around 10-15%.

b) **Sampling issues:** One of the most important reasons is related to mechanism of sampling at loading point. Normally, a sample collected from top of the wagon may not be a representative sample. Further there may be issues in sampling during preparation and testing phases. Resolution of sampling related issues are key to rationalization of coal cost.

Coal grade slippage results into equivalent heat loss, which leads to requirement of purchase additional coal quantity by the generator from open markets at higher rates. To address this, it is recommended that:

a) Tamper-proof, automated, and representative sampling systems—such as auto-mechanical samplers for silo loading, using auger sampling—be mandated at loading points, along with the option of shifting sampling to a neutral location outside coal company premises or CCTV monitoring of the entire testing procedure. Once reliable sampling is ensured, the coal company can be paid on GCV As Billed (at loading point), as per current practice.
b) To address the GCV loss due to methodology of measurement (EB vs TMB), the GCV measured at the loading point on TMB can be used as the basis to

determine the energy charge rate. This will ensure that generators are not liable to pay for the GCV loss due to assessment methodology.

2.2 Rationalization of State levies of taxes and duties on coal

In order to rationalize the taxation on coal, the Central government has removed the GST compensation cess of Rs 400/ tonne and GST rate has been raised from 5% to 18%. Through this, an impact of around 12 paisa/kWh reduction in tariff was achieved.

However, a substantial portion of taxes, royalties and duties on coal are levied by the States which increases the cost of coal.

2.2.1 **Chhattisgarh**

A sample calculation is provided below for SECL mine coal located in Chhattisgarh:

Sl No	Item	Rate (Rs/ton)
1	Basic Charge	975.0
2	Surface Transportation Charges	87.0
3	Sizing Charges	87.0
4	Evacuation Facility Charge	60.0
State Royalties/Taxes/Levies		
5	Royalty Charges (14% of Basic Price)	136.5
6	District Mineral Fund (DMF) (30% of Royalty)	41.0
7	**Adho Sanrachna Vikas***	11.3
8	**Pariyavaran Upkar***	11.3
9	**Forest Tax***	22.8
10	IGST-State Component (9%) on Assessable Value# of Rs 1434.5	129.11
Central Taxes/Levies		
11	IGST-Central Component (9%) on Assessable Value# of Rs 1434.5	129.11
12	National Mineral Exploration Trust (NMET) Charges (2% of Royalty)	2.7
13	GST Comp Cess	0.0
14	Gross Bill Value	1692.70

* State specific taxes

\# Assessable Value = sum of (1--9+12)

Therefore, in Chhattisgarh, State Royalties, State taxes and duties correspond to nearly 21% of the price of coal while central taxes and duties correspond to 7.8% of the price of coal.

2.2.2 Jharkhand

Jharkhand charges a Mineral Bearing Land Cess vide the Jharkhand Mineral Bearing Land Cess Act (Act 10 of 2024) for augmenting health care services, education, social security services, agriculture, rural infrastructure, drinking water and sanitation and for other necessary purposes in the state of Jharkhand. Initially the cess was Rs 100/ton. This was increased in March 2025 to Rs 250/ton and further increased in December 2025 to Rs 450/ton. Due to this cess, generating cost of stations sourcing coal from Jharkhand will experience a significantly higher impact on their generation costs.

Jharkhand had instituted the COVID Cess of Rs 10/ton (issued through gazetted notification 318 dated July6, 2020 for 3 years) and Composition User Fee of Rs 60/ton (through the Jharkhand Highways Fee (Determination of Rates and Collection) Amendment Rules, 2025). It is understood that the Hon'ble High Court has struck down the provisions. However, it shows the propensity of State Governments to arbitrarily charge cess/levies on coal.

2.2.3 Uttar Pradesh

Under the Indian Forests Act, 1927, States have the power to regulate and levy fees on the transit of coal and other minerals. Accordingly, transit fees are being charged by the States bearing coal and also States through which such coal is transited. In case of Uttar Pradesh, Northern Coalfields Ltd is charging UP transit fee @ Rs 38/ton in addition to Madhya Pradesh transit fee of Rs 57/ton. The combined effect of these charges come to around seven paisa/kWh.

As States are already provided with royalty on coal, it is recommended that different types of local taxes imposed by States may be removed/reduced and it would bring down the cost of coal-based electricity generation by about 7-20 paise/unit.

2.3 Royalty calculation methodology:

Royalty is normally considered by States on the notified prices of coal @ 14% as base on ad valorem basis. While the royalty rate on coal is 14% ad valorem in Jharkhand, the base for royalty calculation is the average price of coal sold from the mine, (including the price of notified coal and auction coal), which is generally higher than notified prices. It has impact on the generation cost of stations sourcing coal from Jharkhand - up to 10 Paise/kWh.

It is recommended that royalty calculation being done by Jharkhand may be aligned with the methodology followed by other States.

2.4 Mine Specific charges: Mine Specific charges policy was issued by Coal India Limited (CIL) in 2011. Under the policy a premium is added to the standard notified price for coal from designated mines ostensibly for recovering the cost of mining. This additional "mine specific" charge, or add-on, allows coal companies to set prices based on the specific source, which is then applicable to all buyers of that coal. Other charges, taxes, and levies also apply on top of this notified price.

Mine Specific charges from Rajmahahal mine of Eastern Coalfields Limited (ECL) increased to ₹700 per tonne from ₹ 450 per tonne in November 2024. The tariffs of Farakka and Kahalgaon stations of NTPC are impacted up to 61 paisa/kWh. Also, applicable mine specific charges from WCL mines are ₹450 per tonne. Impact of such mine specific charges are about 30 paise/unit in variable charge of generation.

There are also other instances of coal companies charging extra price for supply to their consumers, such as the Singrauli Punarasthapan Charge of ₹300 per tonne over the notified price of coal for all coal supplies from NCL on February 2025 (Sub judice under Madhya Pradesh High Court).

It is recommended that mine specific charges may be rationalised and issued with due consultation of stakeholders so that cost of generation could be reduced. Further, a Coal Regulator may be notified for approval of costs for cost plus mines.

2.5 Performance Incentive: The ACQ quantum is based on 85% plant load factor (PLF) of the power company. Coal companies charges performance incentive from procurers of coal in addition to notified coal prices, whenever coal off-take is more than 90% of Annual Contracted Quantity (ACQ). Performance Incentive is 10%, 20% and 40% of notified coal prices, when coal off-take is between 90-95%, between 95-100% and more than 100%. The following table illustrates this.

Percentage of actual deliveries*	Percentage of Incentive at the rate of weighted average Notified Price of Grades of Coal supplied
Above 90% but up to 95% of ACQ	0 - 10
Above 95% but up to 100% of ACQ	10 - 20
Above 100% of ACQ	40

Pit head power stations save on transportation costs and are expected to generate at very high plant load factors (>85%). Higher coal costs due to incentive takes away the expected benefits.

For NTPC alone, the potential reduction on this account is Rs 1,130 Crores per year. If CIL supplies full PPA requirement at notified price to NTPC stations it may lead to reduction of 2.7 Paisa/kWh in electricity generation costs. In some cases, the benefits could be as high as 18 paisa/kWh for some Eastern Coal Field (ECL) fed stations.

Further, under the Flexi-Utilization Policy of Coal, the aggregation of ACQ of units/ plants of a State/Central Genco is done on the subsidiary level. Therefore, the higher incentive gets triggered for coal companies supplying additional coal to non linked plants under the scheme. The impact of this is of the order of Rs 190-340/MT depending on the coal grade resulting in increase of ECR by 13-24 paisa.

Therefore, it is recommended to reduce the performance incentive payable by the procurers of coal and incentive below 100% ACQ may be discontinued with and a modest incentive upto 10% for deliveries above 100% ACQ may be considered.

2.6 Shortfall in supplies: In the year 2024-25 NTPC faced shortages from CIL subsidiaries such as Central Coalfields Limited (CCL) and South Eastern Coal Fields Limited (SECL). The FSA materialization to NTPC was 60% for CCL and 86% for SECL. To mitigate the gap costly ECL and BCCL coal was supplied leading to higher cost due to higher cost of coal and performance incentive. Therefore, the power sector is penalized for lower coal supply from linked mines which is not proper.

It is recommended that upto FSA quantum payment to be made to the coal company as per the mine charges for linked mine only.

2.7 Premium payable for Bridge-Linkage: Bridge Linkage'[3] acts like a short term linkage to bridge the gap between requirement of coal of a specified end use plant of central and state PSUs and the start of production from the linked allotted coal mine/ block. While coal under Bridge Linkage is to be supplied on best effort basis with no liability on the coal supplier for under supply, a 40% premium[4] is charged for such coal supplies. This premium has an additional impact of Rs 450-1700/MT depending on the coal grade resulting in increase in ECR of 35-100 paisa/kWh. Coal India being a monopoly is not subject to any prudent and independent cost verification.

It is recommended that there shall not be any premium charge on coal supplied under Bridge Linkage.

2.8 Railway Freight Rate: For a non-pit head station, railway transportation charge for coal contributes significantly to cost of electricity generation. For a typical non-pit station located about 1000 km from coal mine, railway transportation charge is about ₹1900 per tonne of coal *(which contributes to around ₹1.45 per kilo watt hour in variable charges)*, while coal charge for G-12 grade is about ₹1700 per tonne, which translates to more than ₹1.3 per kilo watt hour in variable charges.

Coal stands as the single largest contributor to railway freight, with an average share of nearly 49% of total freight income amounting to Rs. 82,275 Crore in the fiscal year 2022-23 alone[5]. However, Railways charges higher freight for coal (by ~30%) in order to meet social obligations and to cross subsidize the passenger tariffs[6]. This increases the cost of power by Rs 0.10-0.15/kWh on an average basis for pan-India basis.

In order to minimize the logistics issues, upcoming thermal capacities are being preferably planned in proximity to coal mines (pit head stations). While short distance transportation is desirable from a national perspective, the existing freight rate structure inadvertently penalizes short-distance transportation, resulting in disproportionately higher freight charges for plants situated near the source. The following figure brings out the rate per tonne applicable for freight transport as a function of distance.

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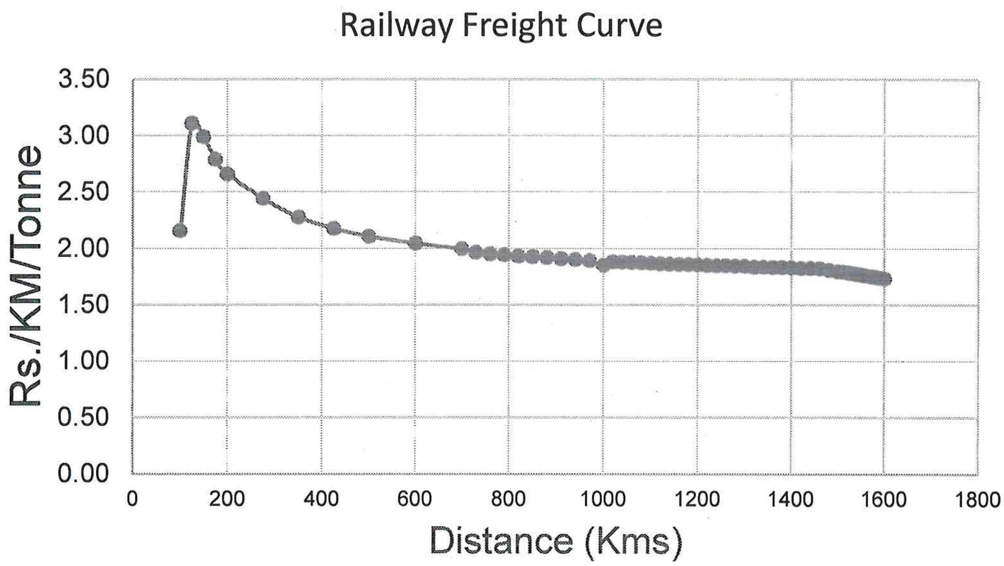
[3] https://coalcontroller.gov.in/files/guidelines-acts-documents/bridge_linkage_policy_08_02_2016.pdf
[4] https://www.mahanadicoal.in/Business/Files/Notice%20397.pdf
[5] India's Coal Boom, PIB. [Available] https://www.pib.gov.in/PressReleasePage.aspx?PRID=2118788
[6] Indian Railways and Coal-An unsustainable interdependency, Brookings India, 2018. [Available] https://www.brookings.edu/wp-content/uploads/2018/07/Railways-and-coal.pdf



Source: Railway Board Circular No. 19 of 2018

It is recommended that

- **Cross subsidy to passenger traffic partly being passed to freight should be phased out over a period of time through a specified trajectory.**
- **Freight rate for short-distance transportation be rationalized and aligned with the rate per Tonne-kilometre applicable to longer hauls.**

2.9 Concessional Power on Fuel Charge basis only to be discontinued:

The policies of some of the states like Odisha (2008 Policy), Chhattisgarh and MP (2012 Policy) mandates supply of 5%-12% of power on variable charge basis to host states from the projects being developed in the states.

It may be mentioned herein that this concessional power supply obligation was introduced at a time when States had control over coal allocation and could recommend granting of coal linkage to IPPs situated within their State. Now, however, coal allocation is entirely governed under the SHAKTI Policy framework wherein States have no role and influence in grant of coal linkages to IPP's.

The fixed cost of new thermal power projects has increased from around Rs 1/kWh in 2008 to around Rs 4/kWh now. With this significant increase in fixed cost, providing 5%-12% power at variable charge only leads to a massive hit for a power plant developer and increases the cost of remaining power to the extent that they would be outbid by developers located in other states.

It is recommended that the States may be advised to remove the requirement of supply of concessional power on Fuel Charge basis to State Discoms from power projects being developed within the States.

2.10 Coal allocation from nearest mines: Pithead Stations are cheapest as they save the cost of transportation. They also help in de-congesting the railway networks. The impact on tariff for a thermal station located 1000 km from the coal mine is of the order of Rs 1.45/kWh whereas the impact of coal cost for G-12 coal may be of the order of Rs 1.3/kWh. For example, the impact of improper mine allocation can be seen in the following table:

<table>
<tr><th>Projects</th><th colspan="2"><u>Indicative ECR for Preferred/ nearest</u> source (Paise/kWh)</th><th colspan="2">Indicative ECR for the Allotted source (Paise/kWh)</th><th>Indicative ECR Impact, (Paise/kWh)</th></tr>
<tr><td rowspan="2">Telangana-II*</td><td colspan="2">SECL</td><td colspan="2">SCCL</td><td rowspan="2">58</td></tr>
<tr><td colspan="2">270</td><td colspan="2">328</td></tr>
<tr><td rowspan="2">Nabinagar-II</td><td>CCL</td><td>NCL</td><td>BCCL</td><td>ECL</td><td rowspan="2">100</td></tr>
<tr><td colspan="2">188</td><td colspan="2">288</td></tr>
<tr><td rowspan="2">Gadarwara-II</td><td>NCL</td><td>SECL</td><td>SECL</td><td>MCL</td><td rowspan="2">42</td></tr>
<tr><td colspan="2">215</td><td colspan="2">257</td></tr>
<tr><td rowspan="2">Meja-II</td><td>NCL</td><td>CCL</td><td>CCL</td><td>MCL</td><td rowspan="2">23</td></tr>
<tr><td colspan="2">255</td><td colspan="2">278</td></tr>
</table>

It is recommended that pit head stations should be supplied coal from nearest mines to the extent, available.

2.11 Revisiting the ash transportation policy: At present, in line with the Ministry of Power guideline No-9/8/2024-St. Th dated 15.03.2024, the entire responsibility for ash disposal is on the Thermal Power Plant. In case of inability of disposal of ash through auctions, the TPP needs to pursue with potential users of ash and provide ash free of cost within 300 km upto their location. While ash is produced by thermal power plants, other activities such as highways, mines need material for earth filling and may use fertile top soil which is not an environmentally benign practice. Therefore, the requirement of utilization of ash is from both sides and there should be obligations on the highway developers, mine developers, etc to utilize the ash. The impact of ash disposal for NTPC is given below:

FY	**Ash Tsp Exp.(Rs Cr.)#**	**Sch. Gen (BU)**	**Indicative Impact on NTPC coal Station Average tariff (Rs/kWh)**
2023-24	3,456.94	336.91	0.10
2024-25	5,287.00	343.04	0.15

figures are provisional and is subject to true up by CERC.

It is recommended that NHAI concessionaires should mandatorily use ash generated by thermal power plants by participating in the ash auction process, so that TPP does not have to incur additional expenditure for transportation of ash to potential users within 300 km.

2.12 Delay in supply of equipment: The country has planned thermal capacity addition of more than 80,000 MW by 2035. Considering limited number of Turbine Generator manufacturers in the country, project commissioning may be delayed and project developers may have to pay penalty for delay in commissioning. This is being built in the tariffs. Recent tenders floated by distribution licensees for procurement of power from new coal-based stations revealed participation by limited number of bidder and first year fixed charge of ₹ 4.5 per unit.

It is recommended that

- In order to encourage capacity building in manufacturing sector, bidding condition could ascertain the spare order book position available with bidders for implementation during the required time frame.
- CPSE under Ministry of Power could be encouraged to participate in the bids floated by distribution license to increase number of bidders and to increase competition.

2.13 Flexible operation of coal based generation: Flexing coal-based plants is essential for addressing climate change as it enables the integration of higher shares of renewable energy, which is critical for reducing greenhouse gas emissions. Coal plants traditionally operate as base load units with limited ability to adjust output, but climate goals require rapid decarbonization through increased deployment of solar, wind, and other variable renewables. By operating flexibly, coal plants act as reliable backup during periods of low renewable generation, preventing blackouts without relying heavily on fossil fuel peaking plants or expensive energy storage. Additionally, flexible coal power supports grid stability by providing ancillary services needed in renewable-heavy systems.

Flexible operation of coal plants in economical manner can allow higher zero marginal cost renewable integration thereby reducing wholesale electricity prices. Further, flexible operation of coal-based plants also reduces energy storage requirement, thus reducing consumer tariff.

It is recommended that intra state and inter state coal based plants should reduce their generation to 40% technical minimum as mandated under Central Electricity Authority (Flexible Operation of Coal based Thermal Power Generating Units) Regulations, 2023.

3.0 Hydro Electric Generation

During 2024-25, generation from large hydro project contributes to about 8% of total electricity generation basket. The per unit cost of hydroelectric power in India, typically ranging from Rs 4 to Rs 6 per kWh for new projects, is influenced by high capital expenditures, long gestation periods, operational inefficiencies, and external factors like delays in clearances. Reducing this involves lowering overall costs (capital, financial, and O&M), while boosting generation output through efficiency gains and higher plant load factors (PLF).

Ministry of Power in its OM on measures to promote hydro power sector dated 8th March 2019[7] inter alia had proposed tariff rationalization measures through back loading of tariff with levelized tariff fixed as per CERC norms. Also, budgetary support for flood moderation component and budgetary support for settling up of enabling infrastructure (such as roads and bridges) was accorded in-principle approval. The availability of budgetary support under enabling infrastructure was expanded vide Ministry of Power OM dated 30th September 2024[8] to include transmission line to pooling point, ropeways, railway sidings and communication infrastructure. Despite the initiatives taken by the Ministry of Power, the estimated tariff for new hydro projects is frequently more than Rs 6.00/kWh. Projects with higher tariff have difficulties in getting power purchase agreements signed by distribution licensees.

Following measures could be considered to reduce cost of hydro generation in India:

3.1 Streamline project execution and delays

In Hydro Projects, construction delays lead to increase in Interest During Cost (IDC) and project cost over-run. IDC sometimes contributes **25–40%** of total project cost in India. Some of proposed solution to address delays could be:

Sl No.	Topic	Solution
1	**Time bound Hydro Clearance**	Hydro projects require Forest, Environment, Wildlife, CEA, CWC, TAC, State and MoEFCC clearances/approval. Time bound clearance/approval can save on average 2-3 years of construction delays experienced.
2	State-led Land Acquisition and R&R	Land acquisition to be completed **before award of EPC contract.** Model R&R package for all Himalayan states under a uniform policy.
3	**Mandatory Geological Investigations** -India suffers frequent geological surprises (e.g., Parbati II, Teesta III, Subansiri).	Geotechnical drilling at ≥ 100 m intervals. Seismic tomography and fault-line mapping before tendering

[7] Measures to promote hydro power sector, Ministry of Power, 8th March 2019. [Available]. https://powermin.gov.in/sites/default/files/Measures_to_Promote_Hydro_Power_Sector.pdf

[8] https://powermin.gov.in/sites/default/files/webform/notices/Modification_of_the_scheme_of_Budgetary_Support_for_the_cost_of_enabling_Infrastructure_for_Hydro_Electric_Projects.pdf

4	**Dispute Resolution**	Contract documents should have provision ***"Dispute Resolution Mechanism through Dispute Resolution Committee" notified by MoP***

The above measures could reduce the construction delays by about 1-2 years with savings about 10%-20%, which may result into reduction in tariff by about 50 paise/unit.

3.2 Backloading of Tariff: Back-loading of tariff in hydropower is a tariff-structuring approach where cost recovery is shifted toward the later years of the project, resulting in a lower tariff during the initial operating period. This mechanism is particularly useful for Indian hydro projects, which typically face high capital costs, long construction timelines, and significant interest during construction. These factors make early-year tariffs expensive and unattractive for DISCOMs, often delaying PPA signing and project viability.

Key features of back-loading include i) reduced depreciation in initial years, increasing it gradually later, ii) **Extended loan tenure (20–30 years)** to spread repayment over a longer period. **Backloading of tariff could bring** down early-year tariffs by **₹0.60–₹1.20 per unit**, making hydropower more competitive with thermal and renewable options.

It is recommended that back-loading of tariff for hydro project should be considered.

3.3 Rationalisation of free power to Home State As per the Hydro Power Policy 2008, a hydro developer is mandated to provide 12% of the electricity generated from the project free of cost to the State as free power. Further, an additional 1% free power is also allocated for local area development around the project site. Therefore, upto 13% power generated from the project is to be given free of cost. The impact of this on tariff would be around 15%.

The Tariff Policy, 2016 provides that free power may be notified by the Central Government and that the free power may be suitably staggered as decided by State. However, in absence of any notification of the Central Government, State Governments are asking for 13% free power. Although hydropower offers home states benefits like economic growth, job creation, infrastructure development and ability to manage water resources, except a few instances, States have not considered staggering of free power.

It is recommended that the Central Government may notify a lower free power for new projects to keep the tariff of new hydro projects at acceptable level.

3.4 Withdrawal of Water Cess: The powers to levy taxes / duties are specifically stated in the VIIth Schedule of the Constitution. List -II of the VIIth Schedule lists the powers of levying of taxes / duties by the States in entries-45 to 63. No taxes / duties which have not been specifically mentioned in this list can be levied by the State

Governments under any guise whatsoever. As hydropower projects do not consume water but use it non-consumptively, therefore, imposing a water cess seems improper.

However, some States like Himachal Pradesh, Uttarakhand, Jammu & Kashmir, and Sikkim have attempted to impose water cess on hydropower generation. Water cess charged by States are about 50 -60 paise/unit.

It is recommended that States should be advised not to tax electricity in different guises thereby increasing the tariff for the consumer.

3.5 Considering SGST waiver by States: The GST form around 10 % of the total hard cost of a typical hydro project. Waiver of State component SGST (State Goods and Services Tax) on hydropower equipment and inputs, which comprises 50% of the GST, can significantly reduce the overall cost of hydropower projects, thereby lowering tariffs and improving project viability in India. The tariff reduction potential of this measure is around 5% of the capital cost and 25 paisa/kWh savings in tariff for a tariff of Rs 5/kWh.

It is therefore recommended that States may be advised to consider waiver of SGST component for lowering tariff of hydro power stations.

3.6 Extending life of hydro electric projects: Presently, life of hydro electric projects is considered as 40 years. The typical operational life of a hydroelectric project ranges from about 50 to 100 years. Generally, such plants require a major modernization or overhaul approximately every 50 years, during which key components like dams, penstocks, turbines, generators, transformers, and control systems are replaced or upgraded to maintain efficiency and reliability. Extending the life of hydroelectric project to 50 years from present 40 years could reduce the first year tariff by about 2% spreading the depreciation over a longer period of time.

It is recommended that life of hydro projects may be increased from 40 years to 50 years.

3.7 Renovation & Modernization (R&M) of existing old hydropower stations: Renovation and Modernisation (R&M) of hydroelectric projects involves refurbishing, replacing, or upgrading ageing civil structures, turbines, generators, control systems, and auxiliary components to improve plant performance. In India, many hydro stations are 25–50 years old, making R&M a highly cost-effective strategy compared to developing new hydro projects, which face high capital costs, long gestation periods, and significant environmental challenges.

R&M typically enhances turbine efficiency by **2–7%**, improves generator reliability, reduces silt-related damage, and lowers forced outages. These improvements increase annual generation and plant availability, directly reducing the per-unit cost of electricity.

Therefore, it is recommended that R&M of old hydro stations should be actively considered.

3.8 Operation and Maintenance (O&M) expenses for hydro projects: The O&M expenses allowed by CERC for hydro projects in first year is 3.5% and 5% for stations with installed capacity exceeding 200 MW and for stations with installed capacity less than 200 MW, respectively. The operation and maintenance expenses for subsequent years of the tariff period is computed by applying an escalation rate of 5.86% per annum upto 5 years whereafter the O&M expenses are allowed based on actual costs. It has been seen that in some cases, hydro developers have taken a lower O&M expense. A reduction of O&M charges to 2.5% could reduce the tariffs by upto 8%.

It is recommended that Central Commission could review the O&M expenses norms applicable to hydro plants.

3.9 Tariff Based Competitive Bidding for Hydro development: Hydro Projects are developed through regulated mode. However, Hydro projects can also be awarded on TBCB basis to developers by the States. Tariff based competitive bidding on transmission projects has helped in bringing down costs by tapping private sector efficiency. The success of the model has prompted States to adopt tariff based competitive bidding for intra state transmission development.

It is recommended that tariff based competitive bidding for hydro projects may be taken up for lowering the tariff.

4.0 Variable Renewable Energy Generation

During 2024-25, variable Renewable Energy (RE) contributes to about 13% of electricity generation basket. At 100 GW of installed capacity, the Indian RE sector is the fourth-largest in the world. Yet, it will need to grow phenomenally to meet the India's ambitious target of 500 GW of installed capacity by 2030.

India's RE tariffs—especially for solar and wind—are among the lowest globally due to competitive bidding, declining module prices, and scaling-up of deployment. Typical utility scale solar tariff ranges from ₹2.25–₹2.80/kWh, while type utility scale wind power tariff ranges from ₹2.80–₹3.25/kWh. Plain Vanila Solar and Wind tariff are already lower in the country. Further, following measures can be considered to reduce existing RE tariff in the country:

4.1 Reduction in GST: 56th GST Council in its meeting recommended a reduction in GST rate applicable to renewable energy devices and their parts (solar PV modules, wind equipment, and similar items) from 12% to 5% with effect from September 2025. As these GST changes on renewable devices will have impact on CAPEX cost of new renewable generator, the benefits will start accruing with commissioning of new renewable projects, which typically takes about 18 months.

For composite EPC contracts in the solar/wind sector, as per Ministry of Finance clarification, the effective GST rate is calculated as 13.8% (70% of goods at 12% plus 30% of services at 18%). With the revised rate, the effective GST becomes 8.9% (70% of goods at 5% plus 30% of services at 18%). Thus, there is a net reduction of 4.9 percentage points in the applicable tax rate for such contracts. Accordingly, the reduction in solar tariff due to GST rate cut is estimated to be in the range of ₹0.12 to ₹0.15 per kWh for new solar installations, and to be in the range of ₹0.14 to ₹0.19 per kWh for new wind projects.

Ministry of Power has already advised the State Electricity Regulatory Commission to pass on the benefits on account of GST reduction to end consumers.

While the impact of integration of renewable energy has been largely positive, with increasing penetration of renewables the wholesale prices may increase in future due to integration costs[9]. Therefore, future reduction in costs would not only need measures for reduction in capital cost but also reduction in the costs of integration.

4.2 Cheaper cost of capital

Quantifying risks provides a clear understanding of their relative significance and impact on the cost of capital (CoC). A risky project will get capital at higher interest rates thereby raising the tariff of the project. Risks could arise due to inter alia, delays in land acquisition, delays in obtaining grid connectivity, delays in execution of PPAs, risks due to supply side issues, risks in resource estimation, regulatory risks such as deviation penalties, high Demand fulfilment requirement (DFR) requirements in Firm and Dispatchable RE (FDRE) tenders and risks related to curtailment.

The CoC significantly affects the Levelised Cost of Electricity (LCOE) for RE projects due to their capital-intensive nature. Unlike conventional energy projects, which incur substantial operational/fuel expenses over time, RE projects require most of their investment upfront before commissioning. It is estimated that the reduction of interest on loan by 1% could lead to tariffs getting lower by 9%.

It is recommended that lower interest rates through concessional green finance, sovereign guarantees, or low-cost multilateral funding can be provided to variable RE generation.

4.3 Public procurement of RE equipment:

With energy independence becoming a critical global discussion, India has implemented various tariff and non-tariff barriers to bolster its solar manufacturing sector. Notable measures include the basic customs duty (BCD), the Approved List of Models and Manufacturers (ALMM) and the Approved List of Cell Manufacturers (ALCM). While these policies are designed to promote domestic PV manufacturing, they have also introduced considerable uncertainty around the availability and cost of PV modules.

Land border procurement rules under Rule 144(xi) of the General Financial Rules raise renewable tariffs mainly by restricting access to the cheapest global suppliers (especially from China), creating supply bottlenecks, and weakening price competition in modules and other key components. Rule 144(xi) requires any bidder from a country sharing a land border with India (notably China) to obtain special registration with a "competent authority" before participating in public procurement, including EPC, goods, works, and even sub-contracts.

The rule applies to central ministries, CPSEs, state entities, PSUs, and PPP projects, so most utility-scale solar, wind, and transmission tenders fall under this framework unless explicitly exempted. Because modules and key electrical equipment constitute a dominant share of solar project capex (often more than half), even a 5–10% increase

[9] Ru Li, Yujie Hu, Xiangyu Wang, Boyan Zhang, Hao Chen, Estimating the impacts of a new power system on electricity prices under dual carbon targets, Journal of Cleaner Production, Volume 438, 2024, 140583, ISSN 0959-6526, https://doi.org/10.1016/j.jclepro.2024.140583.

in module prices from constrained sourcing can increase total project cost by around 3–7% and translate into a tariff increase of roughly 10–25 paise per kWh, depending on project structure and financing. While precise impact varies by tender and period, the direction is unambiguous: tight land border procurement restrictions, unless offset by exemptions, tend to increase renewable tariffs in India by limiting access to low-cost, high-efficiency cross-border supply chains.

In order to address the issues, the following may be considered:

- ***Grant a time-bound exemption for supply of "critical components" such as solar PV cells inverters, trackers and BESS cells/packs) by entities from land border sharing countries, till ramping up of domestic capacity.***
- ***To reduce long-term dependence on imports, the focus could shift from procurement restrictions to:***
    - ***PLI-style support for high-efficiency modules, trackers, inverters and BESS, with clear performance and localization targets.***
    - ***Duty rationalization on key inputs (e.g., wafers, glass, trackers, BESS components) to lower domestic manufacturing costs and make Indian modules competitive.***
    - ***Standardization and quality norms to ensure that domestic equipment is bankable and can compete in auctions without artificial protection.***

5.0 Energy Storage

The rapid increase in variable renewable energy (VRE) — mostly solar and wind — leads to times when generation exceeds demand (midday solar peaks) and times when demand is high but generation low (evenings, cloudy/windy days). Storage smooths out this mismatch. Short-duration battery storage (2–4 hours) will likely dominate early deployment (especially for evening peak loads), while longer-duration storage (pumped hydro or large-scale storage) will become more important for deep decarbonization and grid balancing over days or seasonal swings.

In recent tenders floated in the country, tariff for 2 hour BESS has been observed in the range of ₹2.8-4.7 lakh/MW/month (translating to storage cost of ₹2.3- ₹3.9 per kWh, while tariff for pumped storage (6 hour storage) has been observed in the range of ₹0.85-1.3 cr/MW/year (translating to storage cost of ₹3.9-6 per kWh).

The Central Government has already considered following measures for promotion of BESS and Pumped Storage Projects:

1. Viability Gap Funding (VGF): The government offers substantial VGF (up to 40% of capital cost) for initial BESS projects (4,000 MWh to 13,200 MWh planned), making initial costs affordable and encouraging adoption.
2. Production-Linked Incentive (PLI) Scheme: A massive PLI scheme (₹18,100 Cr) supports domestic manufacturing of Advanced Chemistry Cells (ACC) for batteries, aiming to reduce import dependence and future costs.

3. Transmission Charge Waiver: Waivers on inter-state transmission charges for BESS and Pumped Storage projects for construction work is awarded on or before 30.06.2028.
4. Budgetary support for Pumped Storage Project towards cost of enabling infrastructure, i.e. roads, bridges, ropeways, railway siding, communication infrastructure and transmission line from Pumped Storage Project to the nearest pooling point, including upgradation of pooling substations of State or Central Transmission Utility. The limit of Budgetary Support for the cost of Enabling Infrastructure is ₹1.0 crore/MW for projects up to 200 MW and ₹200 crore plus ₹0.75 crore per MW exceeding 200 MW, for projects above 200 MW. For exceptional cases the limit of budgetary support may go upto ₹1.5 Crore/MW provided sufficient justification exists.

Following measures can be considered to reduce cost of Energy Storage:-

5.1 Reduction on GST on leasing for Energy Storage

Presently, Energy Storage Supplies leases its system to the procurers and the procurers do the charging and discharging. In the leasing service, 18% GST is payable by the procurers. In case GST is reduced to 5% with Input Tax Credit, the cost of energy storage would reduce by about 30-50 paise for BESS and PSP projects.

Accordingly, it is recommended that GST on leasing for Energy Storage may be reduced.

5.2 Extending Viability Gap Funding (VGF) for BESS projects to private discom:

VGF funding for BESS projects introduced by the Central Government is not applicable to private discoms.

The provision of VGF could also be extended to PPPs/private sector Discoms to reduce consumer tariffs in their license areas.

5.3 Introduction of VGF scheme for Pumped Storage Project

Pumped Storage Projects provide critical grid services—long-duration storage, peaking power, inertia, frequency regulation, and integration of high renewable energy. However, despite their system value, PSPs face structural financial barriers that make them commercially unviable without government support. A VGF scheme helps bridge this gap.

PSPs require ₹6 crore/MW for construction—higher than solar/wind or even BESS. Geological investigations, civil works, land acquisition, and tunnelling significantly raise cost. Construction period is 4 years, with long gestation before revenue begins. VGF could offsets part of capital cost, reducing required tariff or storage charges and could promote development of PSP.

Accordingly, a VGF scheme for Pumped Storage project in line with VGF for BESS could be considered to attract investment in the sector and reduce storage cost of PSP.

Chapter 3: Transmission

1.0 Introduction

India today operates one of the world's largest synchronous power systems, comprising nearly **495,000 circuit-km** of transmission lines and **1.35 million MVA** of transformation capacity (2025). The grid's **inter-regional transfer capability**, now about **118,740 MW**, has more than doubled since 2014, reflecting major investment to meet rising electricity demand.

The nationwide integration achieved through **"One Nation – One Grid – One Frequency"** (fully operational since 2013) has transformed power operations by enabling seamless transfer of electricity from resource-rich regions—solar hubs in Rajasthan, renewable-rich Ladakh, and coal-producing eastern states—to major load centres across North, West, and South India. This unified grid enhances system efficiency through improved load balancing, optimized resource utilization, and economic dispatch.

The **National Electricity Plan (2023–32)** targets another doubling of transmission capacity by 2032, backed by an investment plan of **₹9.1 trillion**. Priority focus areas include transmission corridors for renewable-energy zones, smoother grid access regulations, improved Right-of-Way (RoW) compensation frameworks, and transmission readiness for emerging energy-storage systems essential for future grid stability.

Transmission charges have risen sharply in parallel. According to CEA and market data, **annual ISTS transmission charges grew at ~14.9% CAGR between 2011–12 and 2023–24**. This reflects the rapid expansion in infrastructure: transmission lines ≥220 kV increased from **2.21 lakh ckm (2008–09)** to **4.85 lakh ckm (2023–24)**, and transformation capacity rose from **2.89 lakh MVA** to **12.51 lakh MVA**. Recent factors such as policy-driven charge waivers for renewable and storage projects and changing utilisation patterns have further influenced cost trends.

The ways and means to reduce the transmission tariff are discussed in the following paras.

2.0 Recommendations

2.1 Utilisation of Existing Transmission System

Existing high voltage transmission system are not optimally utilized. Average Utilisation of Inter State Transmission System is less than 30%. Improving utilisation of existing transmission assets is one of the most cost-effective ways to reduce transmission charges without constructing new lines. Two major interventions—**Energy Storage Systems (ESS)** and **Dynamic Line Rating (DLR)**—can significantly increase the usable transfer capability of existing corridors.

ESS improve utilisation of the transmission system by smoothing power flows and reducing peak loading on key corridors. During low-demand hours, when transmission lines are underutilised, ESS charges by absorbing surplus generation—including renewable energy—and during peak hours it discharges to serve demand locally. This reduces the instantaneous loading on long-distance lines, relieves congestion, and allows more consistent use of the network across the day.

Dynamic Line Rating (DLR) is a system that determines the real-time current-carrying capacity of a transmission line based on actual weather and operating conditions, instead of using conservative static limits. Conventional static ratings assume worst-case conditions such as high temperature and low wind, which often leads to under-utilisation of transmission lines. When conditions are favourable—especially when wind speed is high or ambient temperature is low—the conductor can safely carry more power. This allows grid operators to increase the usable transfer capability of a line without modifying the physical infrastructure.

Combining ESS and DLR can increase corridor utilisations by **20–40%**, defer large transmission investments, and reduce per-unit transmission charges by **₹0.10–0.25/kWh** through improved asset sweating and reduced congestion.

2.2 Optimise new transmission investment

i) Setting up of planned Load centre near Generation Centre

Establishing planned load centres—such as green hydrogen, data centre, industrial parks, manufacturing hubs, logistics zones, or large commercial clusters—close to major generation centres is an effective strategy to reduce overall power system costs and enhance grid efficiency. When demand is developed near the source of generation, the need for long-distance high-capacity transmission lines is significantly reduced. By consuming power near the generation hub, requirement of transmission network would be less with consequential reduced transmission losses.

ii) Distributed Renewable Energy Generation at load centre

Distributed renewable energy (DRE) generation at the load centre reduces transmission charges by minimising the need for long-distance power transfer and improving utilisation of existing local transmission and distribution networks. When solar rooftops, behind-the-meter systems, C&I solar, and small urban RE plants generate electricity close to consumers, the power is consumed locally without flowing through high-voltage interstate transmission lines. This directly reduces demand on the ISTS network, lowering the total energy that needs to be transported over long distances. As a result, fewer new transmission lines, substations, and evacuation corridors are required, reducing future capital expenditure that would otherwise be recovered through pooled transmission charges.

2.3 Development of new transmission system by adopting tariff based competitive bidding: India's transmission infrastructure is primarily developed and operated by State-owned regional Transmission Companies (TRANSCOs) and central transmission companies like Power Grid Corporation of India (PGCIL). While these entities have played a crucial role in building India's transmission network, many transmission projects under state TRANSCOs face significant and persistent delays due to a combination of procedural inefficiencies, limited accountability frameworks, and resource constraints. This leads to escalation of project costs due to inflation and delayed capacity augmentation that creates bottlenecks and grid congestion. Introducing Tariff Based Competitive Bidding (TBCB) for development of new transmission system in Inter State Transmission System has resulted into reduction of tariff by 30-40%.

Therefore, TBCB may be made mandatory for development of all new transmission system in the country in both Centre and States, except some low value projects and projects of strategic consideration.

2.4 **Rationalisation of Return on Equity (RoE):** Majority of transmission assets are regulated assets and the regulator provide Return on Equity for equity investment on normative basis. The prevailing CERC norms allow RoE of 15.5% on a post-tax basis for transmission entities.

Considering nature of transmission business, it would be appropriate to rationalise RoE for regulated transmission projects taking into account prevalent interest rates in the economy along with an actual risk factor of the investor in power sector in the scenario of improved payment.

2.5 **Budgetary support for RE evacuation infrastructure:** India's large-scale renewable projects are located in remote, resource-rich areas (Rajasthan, Gujarat, Tamil Nadu, Ladakh, etc.), far from load centres. The evacuation infrastructure required to transmit power from these remote renewable energy sources to population centres involves substantial capital investment. The Central Government is already providing budgetary support for development of evacuation infrastructure of renewable energy from such remote areas in the form of Green Energy Corridors.

Offshore wind projects/remotely located solar projects require large and capital-intensive transmission systems, including offshore substations, subsea cables, and long onshore evacuation lines. These transmission components often represent 20–30% of the total project cost, making offshore wind/remotely located solar projects significantly more expensive than onshore/plain land RE projects.

Providing such budgetary support lowers the effective capital cost for developers, improves project bankability, and makes offshore wind/ remotely located RE tariffs more competitive. It also enables early development of transmission "backbone" infrastructure in high-potential zones, supporting scale-up of multiple offshore wind /RE plants. Additionally, public funding reduces risk premiums, accelerates financial closure, and facilitates faster grid readiness aligned with project timelines.

Accordingly, it is recommended that budgetary support/grant may be continued to be provided for development of transmission evacuation infrastructure for off-shore wind and remotely located RE projects.

2.6 **Transmission Charge waiver for Green Hydrogen Projects:** While the electricity sector is progressively eliminating cross-subsidies among consumer categories, the electricity consumers are being burdened by indirect costs for supporting other sectors. Accordingly, the present policy of waiver of ISTS charges for the renewable energy to be used for production of green hydrogen/ green ammonia, should be reviewed.

It is recommended that the waiver could be kept limited to pre-identified RE generation capacity for use in product of green ammonia/ green hydrogen keeping in view the interests of the electricity consumers. The facility of waiver should end after the pre-determined capacity is reached.

Chapter 4: Distribution

1.0 Introduction

India's electricity distribution sector occupies a critical and multifaceted role, serving as the supplier of last resort to all consumers and the financial backbone—or cash register—of the country's power system. It manages an extensive consumer base comprising over 300 million households, millions of commercial establishments across varied geographies, ensuring universal access under the constitutional mandate.

Financially, the distribution sector manages an enormous annual revenue stream—over ₹5 lakh crore in retail tariffs collected during fiscal year 2024. These revenues are essential to meet payment obligations upstream to generation and transmission entities for the electricity supplied, while simultaneously absorbing the burden of multiple forms of operational inefficiencies, regulatory constraints, and subsidized supply mandates.

2.0 Recommendations:

2.1 Addressing AT&C losses: AT&C (Aggregate Technical & Commercial) losses in Indian distribution licensees represent a chronic inefficiency, averaging 16.16% nationally (FY25), but exceeding 25% in many states like UP, Bihar, and Jharkhand. Technical losses (5-8% unavoidable) stem from overloaded transformers, poor conductor sizing, and aging infrastructure, while commercial losses (10-20%) arise from electricity theft, unmetered supply, and billing/collection inefficiencies. High AT&C erodes DISCOM cash flows, widens ACS-ARR gaps (₹1.2 lakh Cr FY24), forces tariff hikes (10-15% avg), delays payments upstream (₹50,000 Cr dues), and deters investments, trapping the sector in a vicious cycle.

1% reduction in AT&C losses could reduce consumer tariff by about 6 paise/unit. Therefore, it is recommended that measures should be taken to reduce AT&C losses in single digit.

2.2 Restructuring of existing loans of DISCOMs: Accumulated financial losses are at Rs. 7.08 lakh crore for state-owned DISCOMs in FY24. The interest cost alone amounts to Rs. 64,000 crores per year. For comparison, in the same year, revenue gaps were closer to Rs. 22,000 crores nationally. Thus, even with efforts to increase revenue recovery, not addressing past losses will ensure continued cost and revenue gap burdens.

Restructuring of existing loans of DISCOMs through debt/ loss takeover via bonds could be undertaken. Assuming 2% reduction in interest cost, there will be reduction in consumer tariff by about 9 paise/unit. With restructuring of debt, 80% to 90% of regulatory assets will also be addressed.

Accordingly, it is recommended that there could be scheme for restructuring of outstanding loans of DISCOMs.

2.3 Timely issuing of tariff order by SERCs: The regulatory process for determining tariffs involves detailed proceedings by State Electricity Regulatory Commissions

(SERCs), which examine the Annual Revenue Requirements (ARR) submitted by distribution utilities and determine the tariffs that these utilities are permitted to charge consumers. Delays in this regulatory process have become endemic in the Indian power sector, with far-reaching negative consequences. For FY 2025-26, SERCs of 18 States/ UTs have complied in terms of issuance of tariff order for FY 2025-26 as per the timelines of relevant SERC regulation while SERCs of 4 States/ UTs have been lagging behind in issuing tariff order for FY 2025-26 as per respective SERC's relevant timelines. SERCs of 14 States/ UTs are yet to issue tariff order for FY 2025-26.

Tariffs are meant to recover the **Annual Revenue Requirement (ARR)** for each year. If the tariff revision is delayed (e.g., tariff not issued on 1 April but 6–18 months later), the **unrecovered cost accumulates**. When the new tariff is not approved, DISCOM continues to charge the old tariff and DISCOM borrows to finance the gap. A typical 6 months delay for under-recovery of 50 paise/unit could increase the tariff by 3 paise/unit.

Delays in tariff order issuance create immediate cash flow deficits, accumulated carrying costs, and the creation of regulatory assets that perpetually burden the system and consumers.

There is a need to establish a comprehensive national regulatory framework to ensure timely issuance of tariff order by SERCs.

2.4 Timely liquidation of Regulatory Assets: Regulatory Assets (RAs) are created when a distribution company is unable to recover its full cost of supplying electricity through consumer tariffs, often due to delays in tariff revisions, government subsidies not being released on time, or regulatory approvals taking too long. These unrecovered costs are deferred for recovery in future tariff orders along with carrying costs. This increases the overall cost burden on both DISCOMs and consumers. The longer the delay in recovery, the higher the carrying cost, which ultimately gets passed on to end users in the form of higher tariffs.

As of 2024-25, states like Tamil Nadu have regulatory assets estimated at around ₹89,375 crore, Rajasthan over ₹47,000 crore, and Delhi approximately ₹27,200 crore, contributing to a nationwide stock of over ₹1.74 lakh crore (₹1.74 trillion) in regulatory assets across various states.

Accordingly, it is recommended that State regulator to ensure Regulatory Asset is not created except in exceptional cases and existing RA are liquidated in a timebound manner.

2.5 Tariff Redesign to ensure recovery of fixed charge: Implementation of net metering on large scale and migration of C&I consumer through captive route is increasingly exposing Discoms to lower recovery of fixed costs and there are serious apprehensions of increase in cost of electricity for other consumer categories which are generally low-income households.

For example, Assam Power Distribution Company Ltd. has reported the following:

> "The challenges are primarily due to inherent disproportionate recovery rate vis-à-vis cost as per the tariff design. Ideally, fixed cost component shall be recovered as fixed/ demand charges and variable cost component as energy

charges. But the actual retail tariff structure is not in sync with this principle. For example, cost vis-à-vis tariff structure approved for FY 2024-25 for Assam is depicted below:

Cost Structure		Tariff Structure	
Component	Rate(₹/unit)	Component	Rate (₹/unit)
Fixed Cost Variable Cost	3.078 6.475	Fixed Cost Variable Cost	1.793 7.760
Total	9.553	Total	9.553

It is evident that fixed cost to the extent of Rs. 1.285 per unit (42% of fixed cost) got recovered as a part of energy charge.

With reduction in sale of energy, there will be under recovery of fixed cost to that extent as the same is bound to incur irrespective of reduction in sale. Although, the same will be recovered in the truing up subsequently but with the possibility of hike in average rate."

In view of the above, there is a need for a national policy to undertake tariff redesign in a time bound manner to ensure fixed cost recovery through demand charges only rather than energy charges to address cross-subsidy distortions and the fixed cost of supply (including PPA costs and network costs) is allocated amongst the various consumer categories in a fair and transparent manner.

2.6 Time of Day (ToD) tariff related interventions coupled with RPO compliance: Considering lower cost of solar generation, shifting some part of peak demand/agriculture load during solar hours through appropriate rebate/incentive could bring down cost of power procurement by distribution utilities. Currently, off-peak solar rebates are provided in only 7 states. In some states (Rajasthan, Telangana, and AP), discounts are as low as 10%-15%, not reflective of variations in power purchase costs.

Accordingly, it is recommended that ToD tariff design could be implemented in all States, with significant rebate/discount for consumption during solar hours. Besides, ToD tariffs could be extended to consumers with loads greater than 10 kW, which is still not implemented in most states.

2.7 Prepaid metering:

Prepaid meters eliminate Unbilled energy, Meter tampering, meter theft and Human errors in billing. With prepaid metering, DISCOM receives **payment before consumption**. Overall, AT&C losses would reduce considerably with prepaid metering. As there is no receivable, there is no need for costly working-capital loans at **10–12% interest** leading to scope for reduction in scope in consumer tariff.

One of the difficulties associated with pre-paid metering is that even in case of pre-paid metering, consumer has to pay for any revision in past energy charge bills and this disincentivises the consumer not to voluntarily opt for prepaid metering.

It is recommended that appropriate regulatory framework for staggered implementation of pre-paid metering across different consumer categories with separate tariff category for pre-paid metering and incentives for consumers may be put into place.

2.8 Net metering: Net-metering was introduced to encourage small consumers to adopt RE Generation. However, net-metering adds cost to a distribution utility, as the excess solar generation during solar hours gets adjusted against power drawn by consumer during peaking hours, which is generally costly.

Therefore, it would be prudent to restrict net metering with free banking to consumers below 10 kW. For all consumers above 10 kW, either net billing or net metering with cost-reflective banking charges should be levied.

2.9 **Creation of Fuel Surcharge Stabilisation Fund:** DISCOMs levy fuel surcharge bill from the consumer on monthly basis on account of increase in power purchase cost and other costs compared to one approved by regulator. However, fuel surcharge bills vary from month to month, giving tariff shock to the consumers.

It is proposed that a certain percentage of fuel surcharge, as approved by the State regulator for a financial year, can be collected from the consumers along with the monthly bill and actual fuel surcharge incurred by DISCOMs can be adjusted from the collected fuel surcharge. This will help the consumers in avoiding any tariff shock by making the tariff stable to certain extent for a given year.

2.10 **Funding support to private DISCOM:** Private distribution companies, while serving a small fraction of India's consumer base, demonstrate the potential for improved operational efficiency. However, most central government funding schemes are explicitly limited to state-owned distribution companies.

It is recommended that all central government schemes providing capital financing support for distribution infrastructure should be extended to include private distribution companies operating under valid licenses, based on merit-based selection, cost-sharing arrangements, and performance linkage.

2.11 **Timely payment by DISCOMs to GENCOs and TRANSCOs:** Timely payment of power purchase and transmission charges by Distribution Licensees to Generation Companies (Gencos) and Transmission Licensees (Transcos) result in tangible cost benefits through entitlement to early payment rebates and avoidance of Late Payment Surcharge (LPS), as stipulated under CERC Tariff Regulations and Electricity (Late Payment Surcharge and Related Matters) Rules. Improved payment security enhances liquidity for Gencos and Transcos, reduces their working capital requirements, and lowers cost of capital.

Therefore, it is recommended that timely payment of dues be ensured to restrict the pass-through of financing costs into tariffs, thereby contributing to tariff stability and systemic cost reduction across the power sector value chain.

Chapter 5: Regulatory and Scheduling Aspect

1.0 Introduction

Regulatory, scheduling, and consumer-tariff aspects are tightly interconnected in India's power sector. **CERC** regulates Inter State Generation Station and Inter-State Transmission System (ISTS) tariff (PoC, HVDC charges, NLDC/ RLDC fees & charges), while **SERCs** regulate distribution tariffs and transmission charges for intra-state assets under Section 62 of the Electricity Act 2003. Tariff is based on **Cost-plus** principles. Strengthening regulatory scrutiny of capital expenditure, improving forecasting and real-time scheduling, adopting performance-based O&M norms, and increasing corridor utilisation can significantly reduce the pooled cost of procurement. For consumers, these improvements translate into lower retail tariffs through reduced transmission cost, fewer congestion charges, and more efficient use of existing infrastructure.

2.0 Recommendations

Following measures can be considered in this regard

2.1 Capital Structure: Capital structure refers to the utilization of debt and equity for building a project. As per regulatory norms hydro projects have a normative Debt:Equity ratio of 70:30. While a lower equity than 30% can be considered, equity more than 30% cannot be considered for tariff purposes. However, most section 62 projects propose a capital structure with 30 % equity. Higher equity in the project entails a higher amount of return on equity as the norms for return for equity as per regulations is around 15.5% to 17% while debt is available at 9%-10%. A reduction in the proportion of equity would reduce the weighted average cost of capital, leading to a reduction of levelized tariff.

Therefore, to make the projects more viable by reducing the tariff, a debt equity ratio of 75:25, may be considered after discussion with lending agencies. Developers would be free to have a higher quantum of debt investments, after discussions with lending agencies, to further improve the viability of hydro tariff.

2.2 Security Constrained Economic Dispatch (SCED): Distribution licensees have bilateral power procurement PPAs and do not have visibility of the overall resources present in the national grid. Due to this, costly generation may be scheduled to a higher quantum than low-cost generation. To enhance efficiency of the power system, Security Constrained Economic Dispatch (SCED) has been introduced. Under this, the grid operator can reduce the generation of higher cost plants and increase the generation of lower cost plants after the power market gate closures. The national SCED pilot launched by Grid India in April 2019 achieved cumulative savings of ₹25 billion by February 2022 across 58 GW capacity, averaging ₹20 million daily or ~1% reduction in variable generation costs through merit-order redispatch. Intra-state SCED pilots promise even larger benefits, with 2-3% dispatch efficiency gains potentially saving ₹10,000 crore annually sector-wide by minimizing discom procurement costs[10].

It is recommended that intra-state thermal generating stations be advised to intra-state thermal generating stations in SCED mechanism.

2.3 Short term capacity reallocations: Short-term capacity reallocations among distribution licensees could be an important strategy in India's power sector to reduce costs and improve the efficiency of power procurement. Distribution licensees, or DISCOMs, often enter into long-term power purchase agreements (PPAs) with generators that create a contractual obligation to pay fixed charges for a certain capacity, regardless of its utilization. This leads to unutilized generation capacity (UCC) that can become a source of inefficiency, especially when some DISCOMs face shortages during peak demand hours while others have surplus capacity during off-peak hours. Through short-term capacity reallocations, DISCOMs can share this unutilized capacity more effectively, reducing the need for costly new procurement and reliance on expensive real-time markets (RTM).

Power exchanges /Over the counter markets could bring out new products to enable short term capacity sharing.

2.4 Long-term Contract Optimization: Current 25-year PPA durations create inflexibility and stranded cost risks. Many plants lower down in the merit order are underutilized or non-utilized due to higher cost of generation. To achieve the objectives of developing the electricity markets in the country and controlling the stranded costs being borne by the distribution utilities, the reduction of duration of long term PPA may be considered. Concurrently capacity markets could be developed by CERC. However, shorter PPAs may lead developers to recover fixed costs within the first 15 years, potentially resulting in higher tariffs in the initial period.

Therefore, it is recommended that the term of PPA under competitive bidding guidelines and under Section 62 of the Act be reduce to 15 years in a phased manner over a period of time hand in hand with the deepening of electricity markets.

2.5 National Programme for Demand Response: Demand response (DR) reduces the cost of electricity by actively managing and shifting consumer demand to better match supply, thereby improving grid efficiency and lowering the need for expensive peak generation and storage. By incentivizing consumers to decrease or shift electricity usage during high-demand periods or when supply is constrained—such as times of peak renewable variability or transmission bottlenecks. Utilities also achieve improved load factor and deferred infrastructure upgrades. An example of demand response reducing electricity costs in Europe is seen in Germany's Energiewende transition, where large industrial and commercial consumers participate in demand response programs to shift or curtail load during peak periods or grid stress. Through participation in balancing and ancillary service markets, these consumers help avoid

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[10] Optimising Power Despatch: Early lessons from intra-state SCED pilots, SK Soonee, Debasis De, Powerline, [available]. https://powerline.net.in/2025/10/24/optimising-power-despatch-early-lessons-from-intra-state-sced-pilots/

costly use of peaking gas plants and grid reinforcements. The combined effect has been a reduction in peak wholesale prices by up to 20-30% during critical hours, decreasing overall system balancing costs, which totalled around €1 billion annually in Germany as of 2024[11].

It is recommended that all States may conduct pilot DR projects for large consumers for estimation of demand response. State Regulatory Commissions would need to bring in enabling policies in this regard.

2.6 Resource adequacy planning to avoid overcapacity: Implementation of resource adequacy planning ensures optimal capacity procurement to meet demand reliably at least cost. By adopting scientific demand forecasting, accounting for renewable energy variability, energy storage, demand-side response, and inter-regional power transfer capabilities, DISCOMs can avoid over-procurement of generation capacity. Preventing excess capacity mitigates fixed cost burdens such as capacity charges, depreciation, and return on equity, which are ultimately borne by consumers.

It is recommended that all States formulate and implement comprehensive resource adequacy plans to ensure optimal utilization of existing assets, minimize the risk of stranded capacity, and achieve long-term cost efficiency while maintaining prescribed reliability standards.

[11] European Electricity Review, 2024, EMBER, [available]. https://ember-energy.org/app/uploads/2024/10/European-Electricity-Review-2024.pdf

Chapter 6: Conclusion and way forward

The Indian power sector stands at a critical juncture: it has achieved universal access, built one of the world's largest synchronous grids, and added renewable capacity at an unprecedented pace, yet the average cost of supply remains under pressure. With electricity demand projected to more than triple by 2046–47 and the nation committed to 500 GW of non-fossil capacity by 2030, any increase in system cost will inevitably translate into higher consumer tariffs unless decisive corrective actions are taken now.

This study demonstrates that substantial and sustainable cost reduction is feasible across every segment of the power value chain — generation, transmission, distribution, and regulatory processes — without compromising reliability or environmental goals. The identified measures, if implemented in a time-bound and coordinated manner, can collectively reduce the average cost of supply by 50–150 paisa per unit or more, depending on the vigour of execution. Many interventions require no fresh capital expenditure; they simply remove distortions, enhance transparency, and improve asset utilisation.

The highest-impact opportunities lie in:

- Rationalising coal-related levies, charges, and measurement practices that currently inflate thermal generation cost by 50–120 paisa/kWh in many stations;
- Mandating tariff-based competitive bidding and better utilisation of transmission assets to arrest the sharp rise in transmission charges;
- Bringing distribution losses to single digits, restructuring legacy DISCOM debt, and eliminating regulatory delays that perpetuate carrying costs and regulatory assets;
- Introducing market-oriented scheduling tools (intra-state SCED, short-term capacity reallocation, demand response) and rational tariff design to ensure cost-reflective pricing and efficient dispatch.

Several recommendations fall entirely within the domain of the Central Government and its agencies (coal sampling reforms, railway freight rationalisation, GST on storage leasing, VGF extension, SCED expansion, TBCB mandate). Others require coordinated action with State Governments (royalty and cess rationalisation, free power norms, water cess withdrawal, SGST waiver, timely tariff orders, ToD implementation). A few needs regulatory consensus (O&M norms, debt-equity ratio, fixed-charge recovery, net-metering rules).

To convert these recommendations into reality, the Ministry of Power may consider constituting an Empowered Committee with representatives from MoP, CEA, CERC, Coal, Railways, MNRE, State Governments, and industry fora. The Committee could prioritise measures, fix responsibility and timelines, and monitor annual progress against quantifiable milestones. Continuing this exercise as an annual cost-reduction review, as originally envisaged, will institutionalise efficiency gains and keep consumer tariffs among the lowest in the world even as India transitions to a cleaner and more resilient power system.

By acting decisively on the opportunities outlined in this report, India can deliver affordable, reliable, and sustainable electricity to its citizens while honouring its national and international commitments on energy security and climate change. The time to act is now.

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