FLEX TO FIX

Deciphering India's Coal Flexibilisation Challenge for RE integration

Abridged Version

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ACKNOWLEDGEMENTS

This report has drawn upon insights and material from various regulatory bodies, research think tanks, and subject-matter experts, whose work has been cited in the references section. It has also been enriched by direct inputs from experts, whose contributions we gratefully acknowledge here.

List of experts in an alphabetical order:

- Alexander Hogeveen Rutter, Electricity Sector Lead & Manager, Third Derivative
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- Ankit Dubey, Associate Manager, Adani Power
- Ashutosh K. Srivastava, Partner, SKV Law Offices
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- Kapil Mandloi, Operations Head (Trombay TPP), TATA Power Ltd.
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- Tahoor Alam Khan, Counsellor – Energy Efficiency, CII
- Vivek Pandey, Chief General Manager, GRID-INDIA

EXECUTIVE SUMMARY

India's energy transition has reached a pivotal juncture. By November 2025, the nation achieved a significant milestone by reaching 50 per cent non-fossil-based installed power capacity, five years ahead of its original 2030 target. The rapid growth in RE, particularly solar energy, which has seen a 3.5-fold increase in six years, now exceeding **140 GW** of installed capacity, has fundamentally altered the demand–supply balance in the grid, creating deep intra-day variability and operational stress on conventional generation while presenting a fundamental challenge to the stability of the national power grid.

Our power system is in need of a redesign. The rise in RE reflects its evolving and dynamic nature, showcasing a need for evolution. The variable nature of power necessitates a shift away from inflexible power supply, as addition of inflexible resources will add a greater system cost. The power system can add flexibility with a variety of solutions, such as flexible coal, pumped storage, and battery storage. However, in the immediate future, coal retains the largest share of the power generation mix in India by continuing to supply over two-thirds of total electricity generation. This highlights the need to transform the major source of our power system into a flexible resource.

The need for this transition is further exposed by a structural mismatch in India's power supply. While renewable energy is variable and concentrated during daytime hours, India's electricity demand shows a second peak in the evening. The resulting "duck curve" has deepened significantly, forcing coal-based thermal power plants to ramp down during solar hours and ramp up sharply during evening peaks. Yet, India's coal fleet is designed for stable, baseload operation and is currently constrained by a minimum technical load (MTL) of ~55 per cent, limiting its ability to respond to these dynamic requirements. Hence, the first step to responding to greater renewable energy integration for the future is to flex our coal-based thermal energy supply.

7.61 TWh
of renewable energy curtailed between April 2025 and March 2026

70 GW
of net load ramps and demand variability

≥Rs12/kWh
of natural gas is relied upon to meet demand surge

Scale of the Problem

The consequences of this inflexibility are already visible:

- 7.61 TWh of RE curtailed (generation and transmission) in FY 2025-26,
- Increasing reliance on high-cost gas generation (~Rs 12/kWh) to meet demand surge,
- Rising net load ramps and demand variability exceeding 70 GW,
- Persistent high-frequency grid events due to over-injection, indicating system imbalance.

These trends represent both an economic loss (unused low-cost renewable energy) and a system risk (grid instability and inefficient dispatch). With an additional 100+ GW of solar capacity under construction, these challenges are expected to intensify unless system flexibility is urgently addressed.

Scale of the National Initiative

To address these challenges, the Central Electricity Authority (CEA) has mandated a phased implementation plan to cover 493 thermal units (196.7 GW) by 2030. The core objective is to reduce the MTL of these units from the current 55 per cent to 40 per cent, while enhancing ramp rates to at least 3 per cent per minute.

- **Technical feasibility:** Pilot studies have confirmed that most Indian coal units can technically operate at 40 per cent MTL, with some units even reaching 34 per cent.
- **International benchmarking:** The report draws on the experiences of **China**, which has already retrofitted over 300 GW of its fleet, and **Germany**, which uses a mature market-driven approach for 15-minute dispatch blocks to manage flexibility.

Implementation Reality: Significant Gap

Despite strong policy intent, implementation remains significantly behind schedule:

- Only ~1 unit (500 MW) has fully demonstrated both low-load and ramping compliance,
- Only ~1.9 GW has achieved 40 per cent MTL capability,
- Even the pilot phase (originally 5.85 GW) remains incomplete, with only 800 MW effectively achieved.

This indicates that India is still effectively in a pilot-stage reality, despite entering Phase 1 of the national rollout. The gap is not due to technical infeasibility, as pilot studies have already demonstrated feasibility, but rather due to institutional, regulatory, and financial bottlenecks that continue to limit progress.

~1unit	1.9 GW	91 units
of 500 MW has demonstrated low load and ramping compliance	of capacity has achieved 40 per cent MTL capability	under Phase 1 of CEA's phasing plan are behind schedule

Cost and Economic Trade-Offs

Flexibilisation is not cost-neutral, yet it is the most cost-effective near-term solution for RE integration. It involves:

- CAPEX: Rs 6–30 crore per unit depending on vintage
- OPEX impacts: higher coal consumption, auxiliary usage, and life consumption
- Estimated tariff increase of ~8–15 per cent on a daily basis for flexible operation

However, when compared with alternatives:

- Short-duration BESS: ~Rs 0.8–1.0 per unit
- LDES (projected): ~Rs 3.0–4.5 per unit
- LDES (current): up to ~Rs 7.1 per unit

Flexibilisation remains the least-cost near-term solution, particularly given the scale required. Large-scale storage deployment, while essential in the long term, would require Rs 1.08–1.39 lakh crore (short-duration) and up to Rs 9.6 lakh crore (long-duration), significantly higher than retrofit-based flexibility.

System-Level Scenario Assessment

CSE analysis showcases net benefit for flexibilisation across the sector with greater RE integration, net CO_2 emission reductions alongside systemic portrayal on need of flexibility in the long run.

- ~125.1 TWh of additional annual RE integration space
- ~ 18,148 MW of additional RE absorption space during high solar hours
- ~ 92–101 million tonnes of CO_2 annually OR ~ 7.7–8.4 per cent net emissions reduction in the power sector

Key Structural Challenges

The report identifies five critical barriers:

1. **Implementation delays** in the phasing plan
2. **Regulatory asymmetry** between central and state frameworks
3. **Incomplete cost recovery mechanisms**, especially for OPEX and hidden costs

4. **PPA and contractual rigidities**, misaligned with flexible operation
5. **Environmental externalities**, managing efficiency and emissions

Additionally, inclusion of **old and inefficient units** in retrofit plans raises concerns on cost-effectiveness and long-term system efficiency.

Way Forward: Strategic Recommendations

To enable a scalable and cost-effective transition, the report proposes:

1. **Factors for reconsideration and prioritization in the Phasing plan:**
   - Heat-rate and Emission performance,
   - Consideration of greater utilisation of efficient and low-emission assets,
   - Consideration of two-shift operation for old and inefficient plants,
   - Technological limits of thermal units.

2. **Restructure compensation:** Broaden CAPEX/OPEX definitions to include mandatory training, workforce upskilling, and the costs incurred during trial or testing periods.

3. **Incentivise compliance:** Move beyond penalties. Establish incentives like **preference in Merit Order Dispatch** or lump-sum payouts for units that achieve flexibility targets.

4. **Mandate transparency:** Standardise the disclosure of RE curtailment costs to make the economic and environmental impact visible to planners and the public.

5. **Baseline unit health:** Conduct structured health assessments of units before retrofitting to distinguish between legacy wear-and-tear and flexibility-induced damage.

6. **Fuel and emission standards:** Mandate fuel quality assurance to reduce unit tripping during ramping and establish SOPs to manage the higher local air pollution caused by inefficient part-load operations.

7. **System flexibility based on cost competitiveness:** Strategise power system flexibility based on cost competitiveness by subjecting BESS at thermal plants to cost-reflective market dispatch, allowing transparent comparison with lower-cost flexibility alternatives.

~125.1 TWh	~18 GW	~92/101 MT
of additional annual RE space created by implementing flexibilisation	of RE absoprtion space created during solar hours	of net CO_2 savings by implementing flexibilisation

8. **Integrate time-of-day (TOD) pricing**: Operationalise time-of-day pricing with market-linked dispatch to enable thermal plants to competitively supply un-requisitioned power based on real-time price signals, thereby incentivising flexibility and improving system efficiency.

Conclusion

India's energy transition has entered a phase where flexibility, not capacity, is the binding constraint. While renewable energy expansion has outpaced expectations, the supporting ecosystem, particularly thermal flexibility, has not kept pace as the current report's assessment shows.

Flexibilisation of coal-based thermal power plants represents the bridge between today's coal-dependent system and a future renewable-dominant grid. It is a practical, scalable, and cost-effective solution in the near to medium term. However, without urgent course correction in implementation, regulatory alignment, and economic incentives, India risks rising curtailment, higher system costs, and grid instability, undermining the very gains of its renewable energy transition.

The next phase of India's power sector reform must therefore move decisively from policy design to execution, ensuring that flexibility becomes an embedded feature of the system, not a delayed afterthought.

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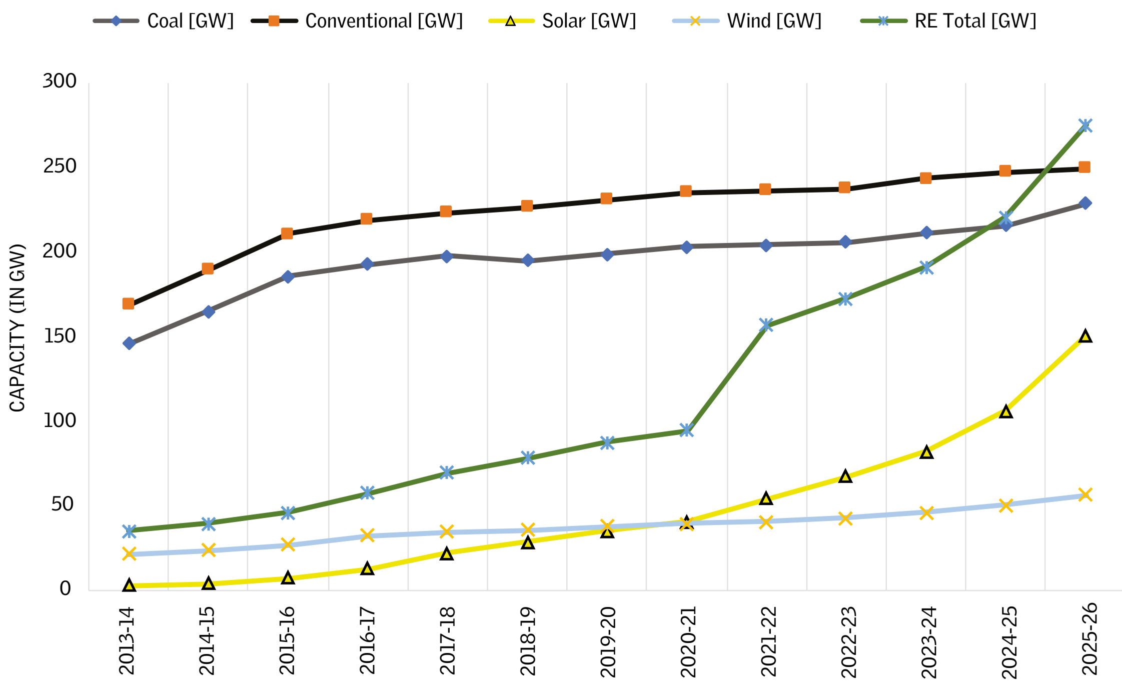
Graph 1: Evolution of India's Power Installed Capacity Mix (2013–14 to 2025–26)



Source: CEA's monthly installed capacity report

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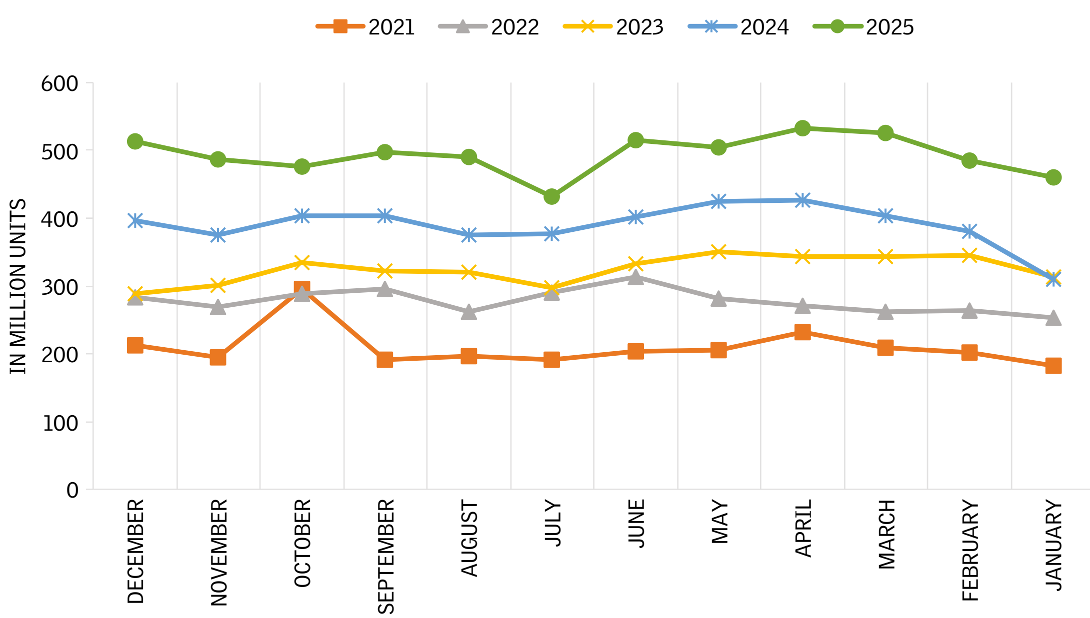

Source: CSE analysis of CEA's Daily Renewable Generation Report (2020–2025)

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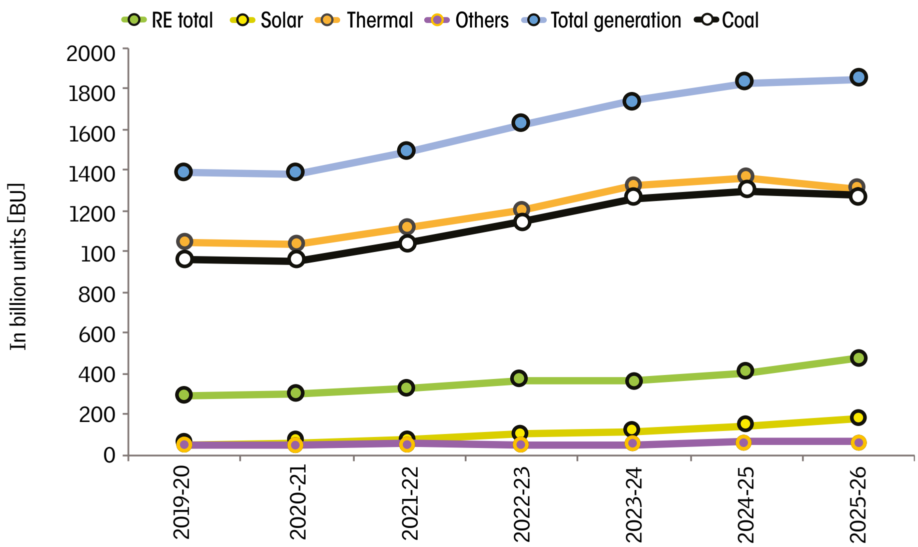

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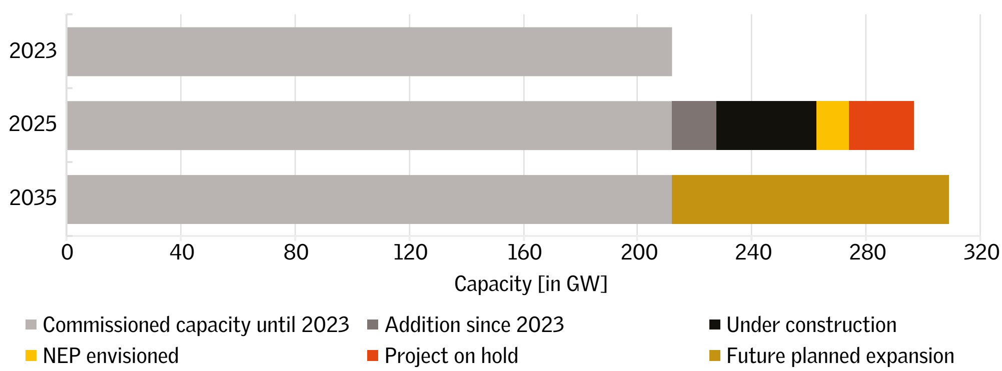

Source: CSE analysis on basis of multiple GoI policy documents

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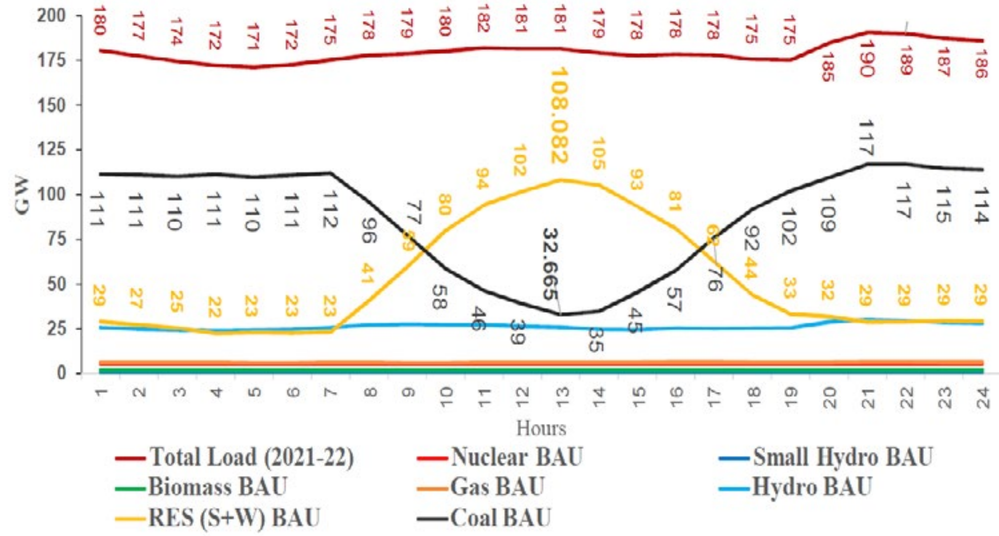
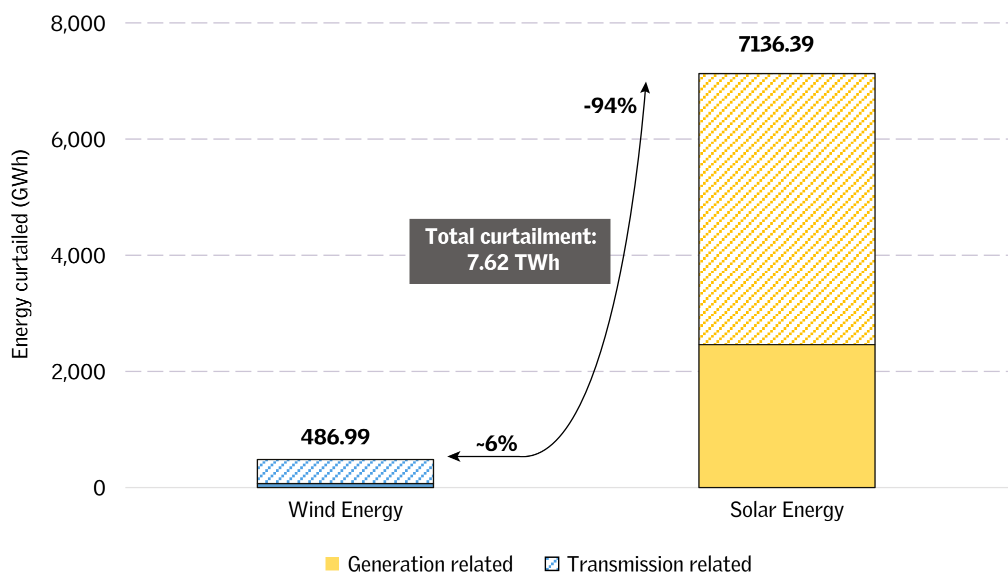


Source: CEA Report: Flexible Operation of Thermal Power Plants for Integration of Renewable Generation

Graph 7: Renewable Energy Curtailment in India (FY 2025–26)



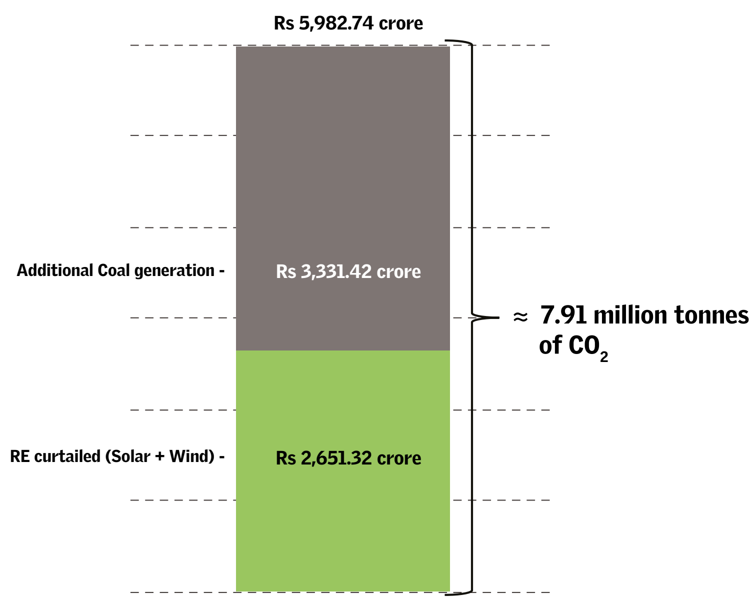
Source: CSE analysis of GRID-India VRE reports

Table 14: RE Curtailment Cost Assessment

Energy Source	Curtailed Energy (in GWh)	Cost Per Unit (Rs/kWh)	Total Cost (in Rs crore)
Solar	7,136.39	3.46	**2,469.19**
Wind	486.99	3.74	**182.13**
Total	7,623.38	—	**2,651.32**

Source: CSE analysis

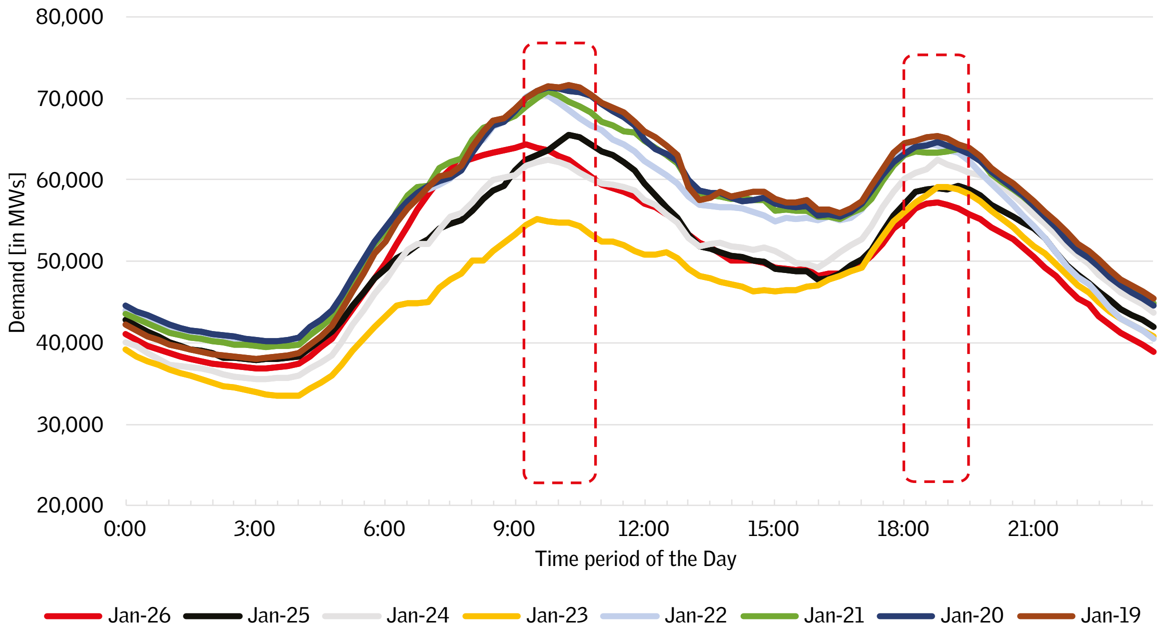
Figure 11: Total Shadow Cost of RE Curtailment (FY 2025–26)



Source: CSE analysis

Taken together, the financial and environmental impacts demonstrate that renewable curtailment is not merely an operational inefficiency but a systemic cost burden. Consumers effectively finance unused clean energy, pay again for fossil replacement, and absorb the associated emissions externality in the form of avoidable carbon dioxide releases and their broader environmental and health implications. Curtailment therefore manifests as a structural misallocation of system resources, with its shadow costs undermining both economic efficiency and decarbonisation objectives.

Graph 8: Power Demand of Northern GRID (January 19–26, 2026)



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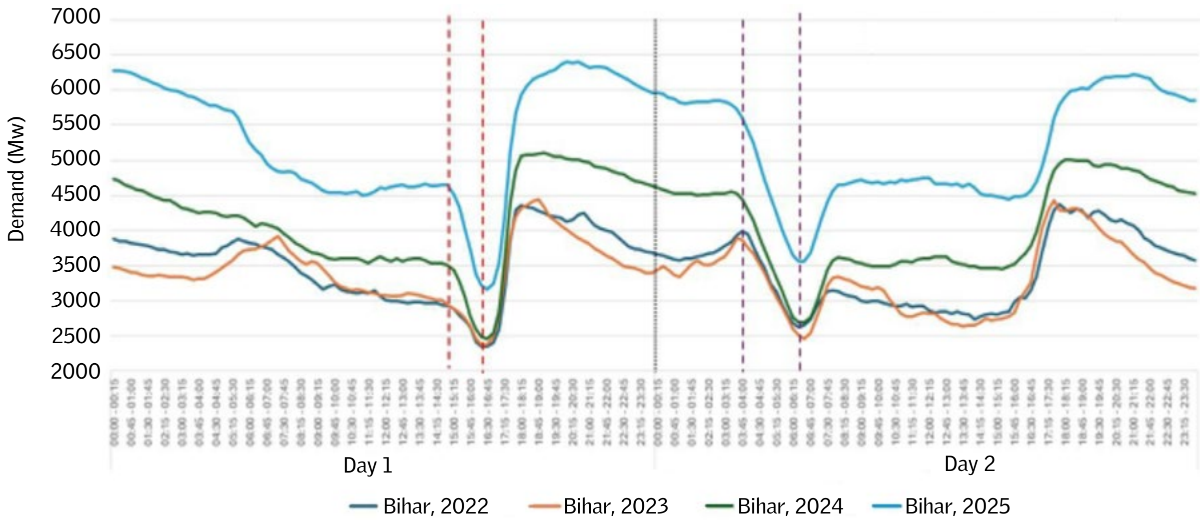

Source: GRID-India

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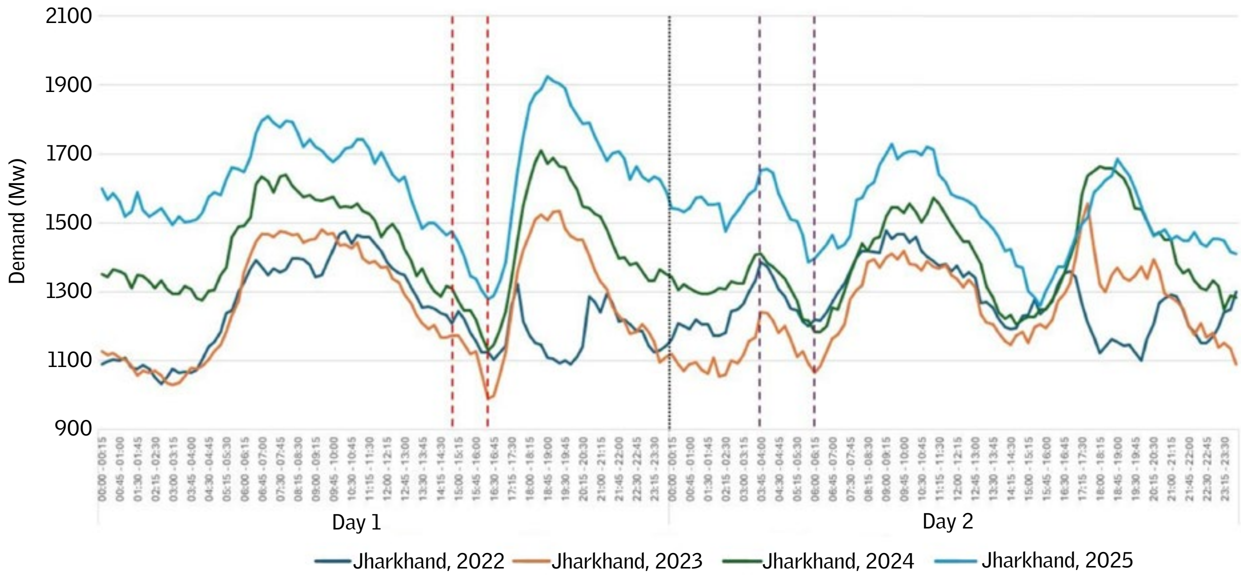

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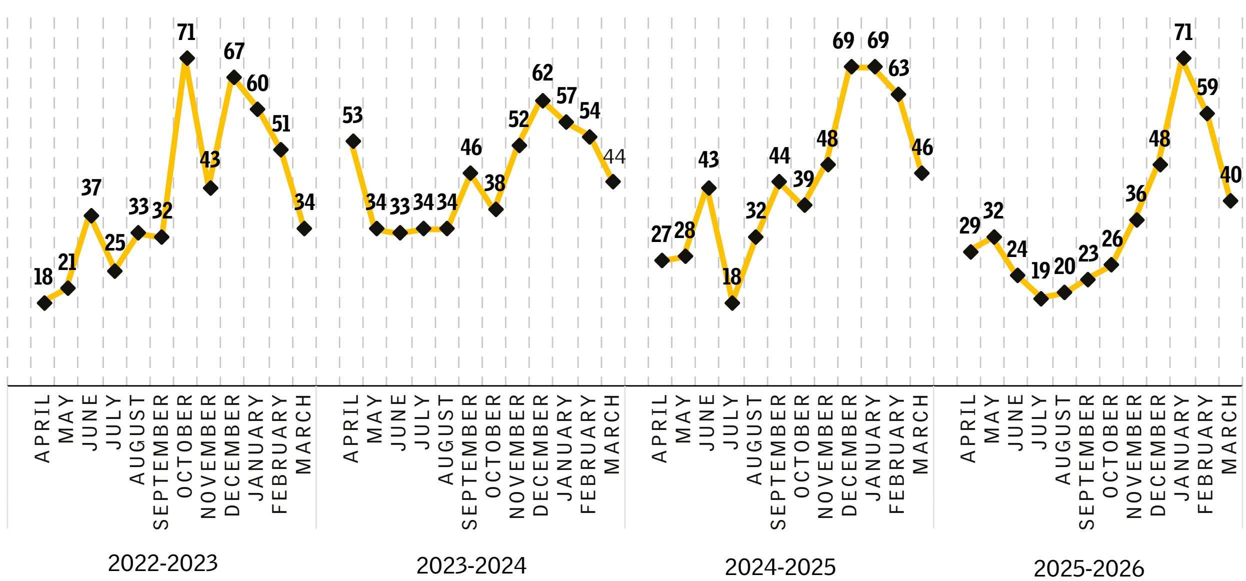

Source: CSE analysis of GRID-India's monthly forecast figures

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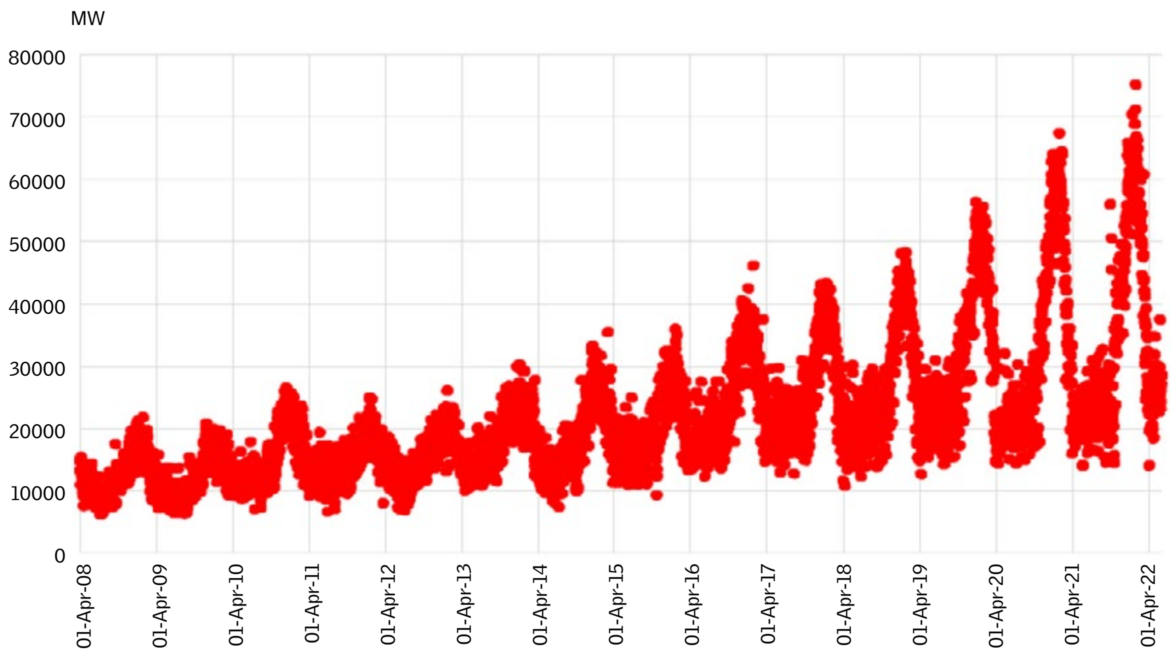
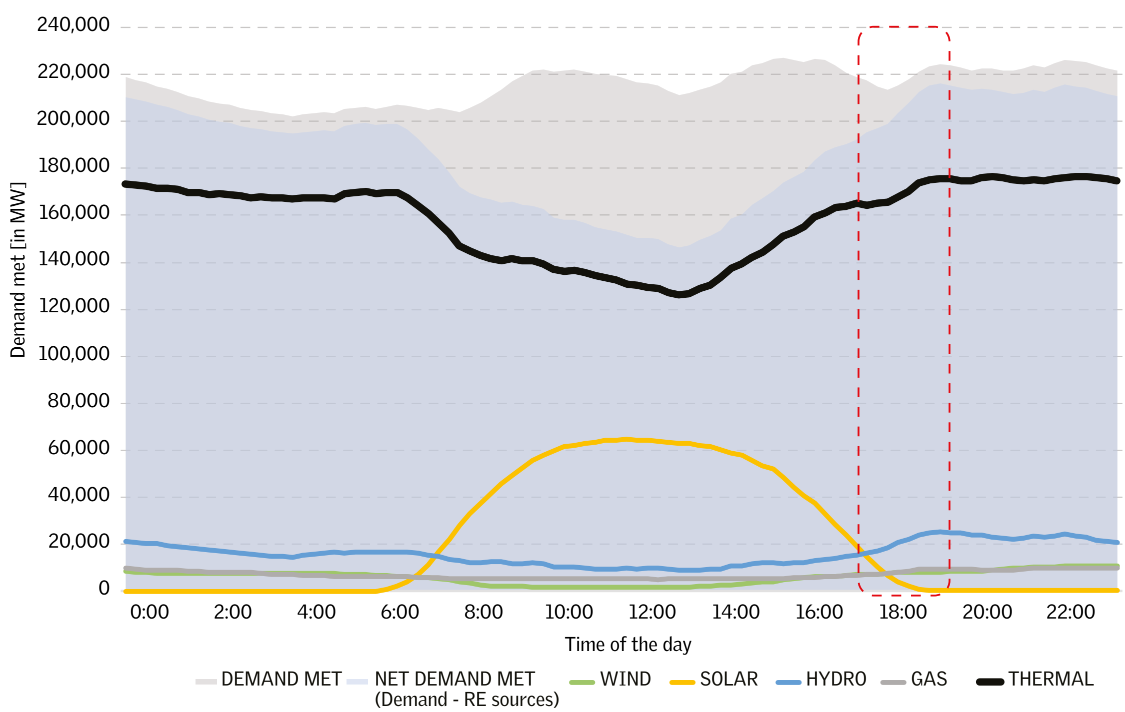


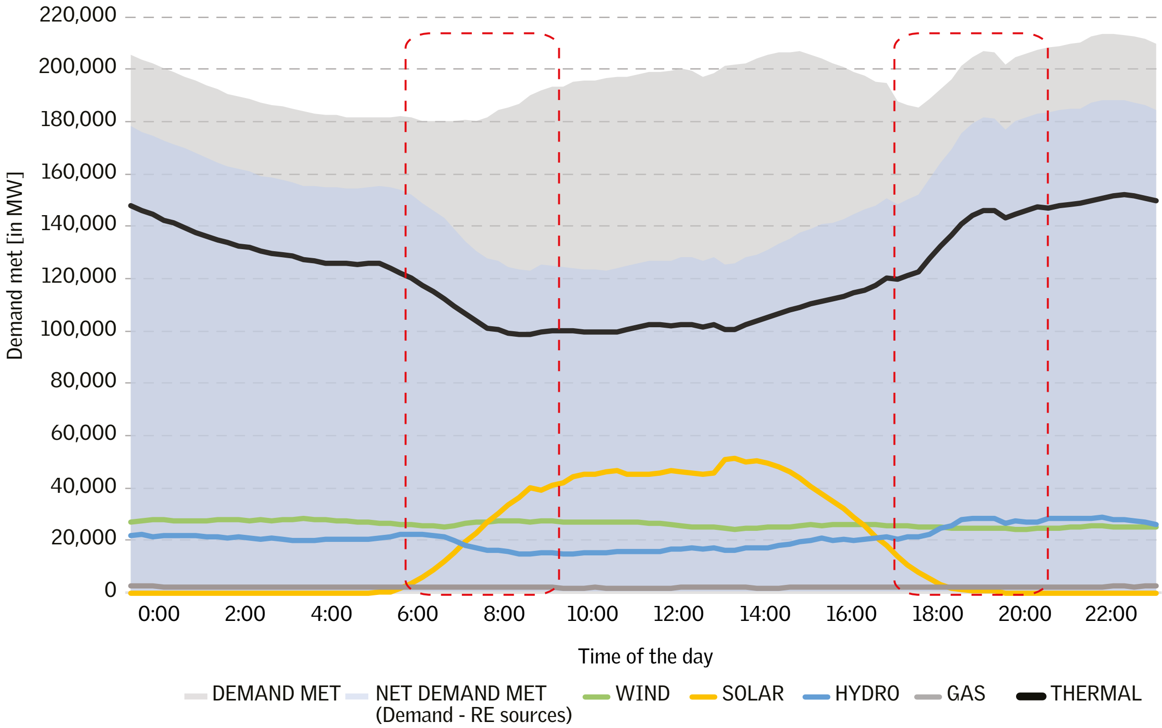
Source: CEA Roadmap for Flexibilisation, February 2023

Graph 12: All India Demand Met: April 23, 2025



Source: GRID India Daily PSP Report – April 23, 2025

Graph 13: All India Demand Met: May 31, 2025



Source: GRID India Daily PSP Report – May 31, 2025

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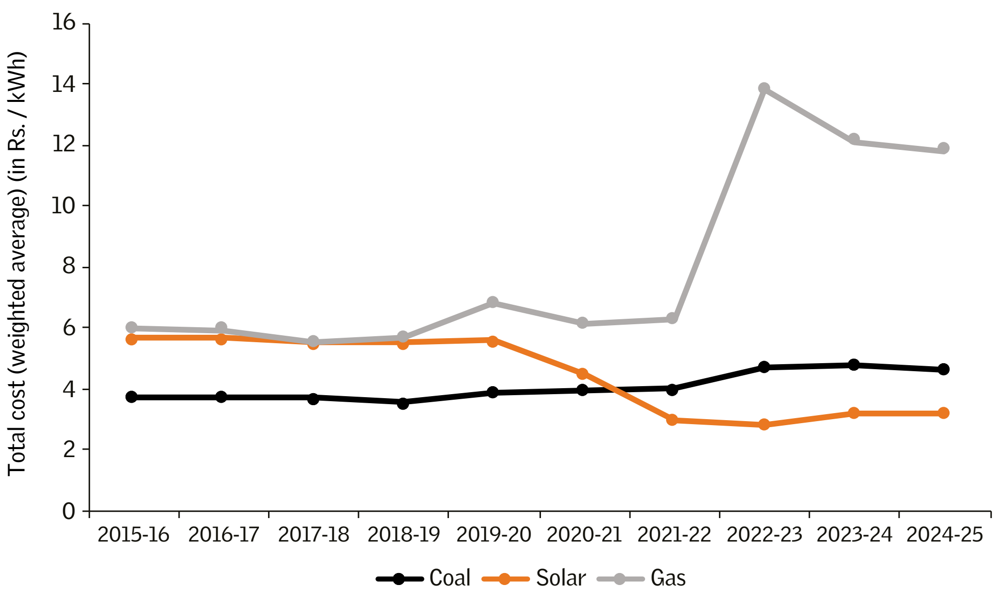

Source: India Climate & Energy Dashboard

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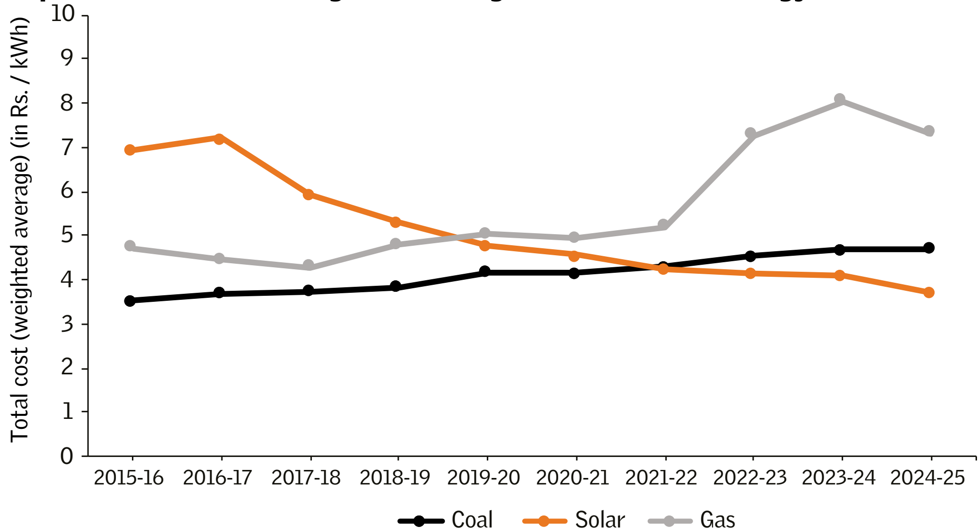
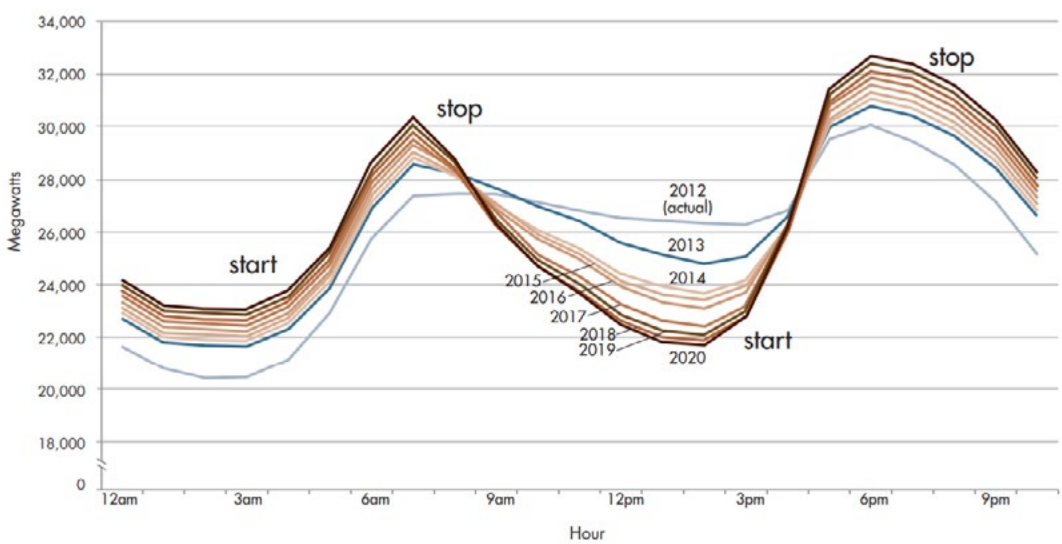


Source: India Climate & Energy Dashboard

Graph 16: Indicative Duck Curve: California Net Load



Source: California Independent System Operator: Fast facts on duck curve

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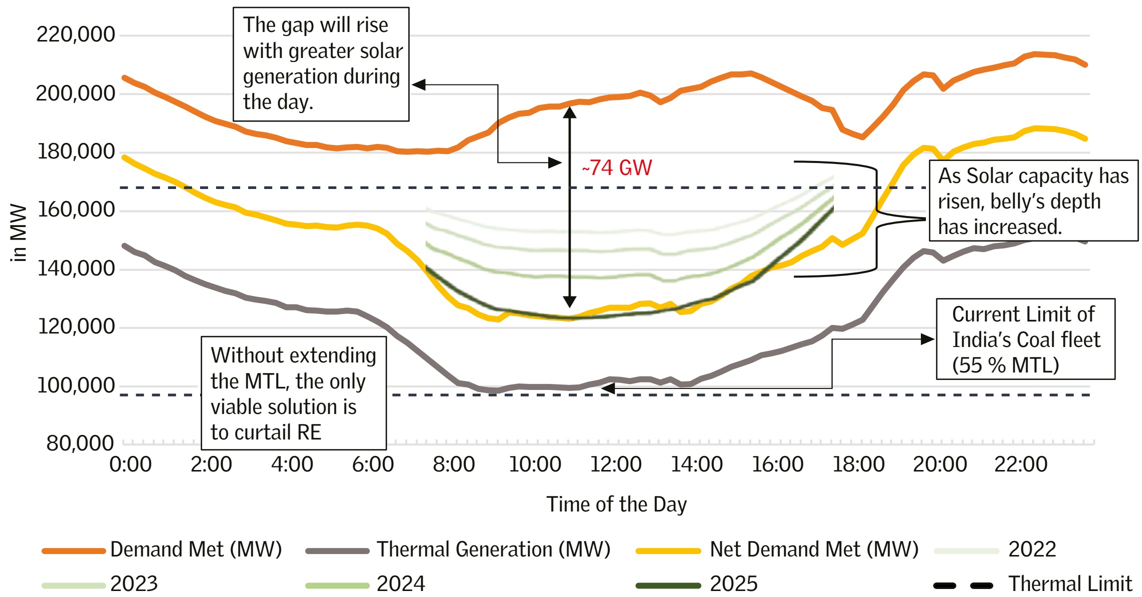

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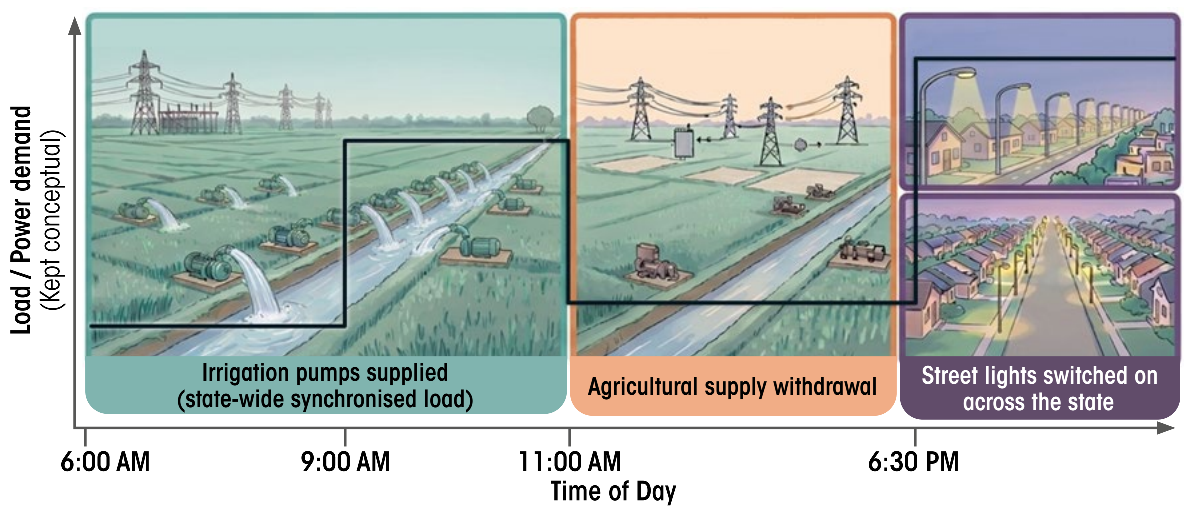
Similar type of electrical loads come online simultaneously across India, causing sudden jumps in power demand



Source: CSE analysis + Google Nano Banana usage

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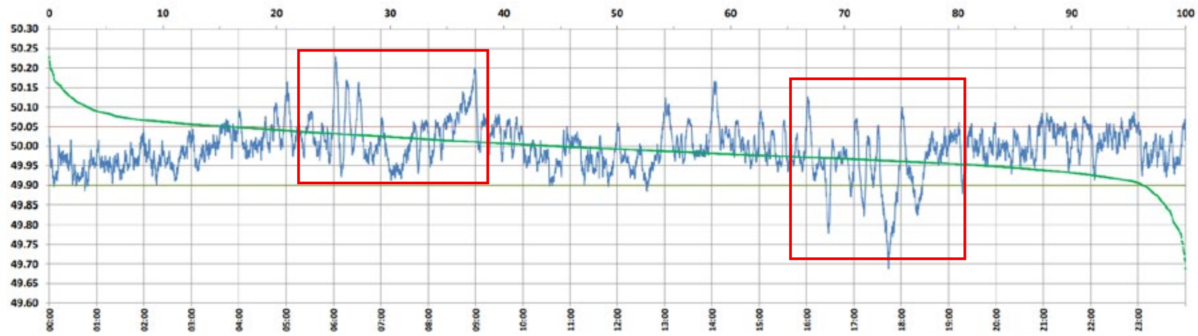

Source: GRID-India – Daily frequency profile report

RISK OF GRID STABILITY BY OVER-INJECTION RECORDED IN 2024

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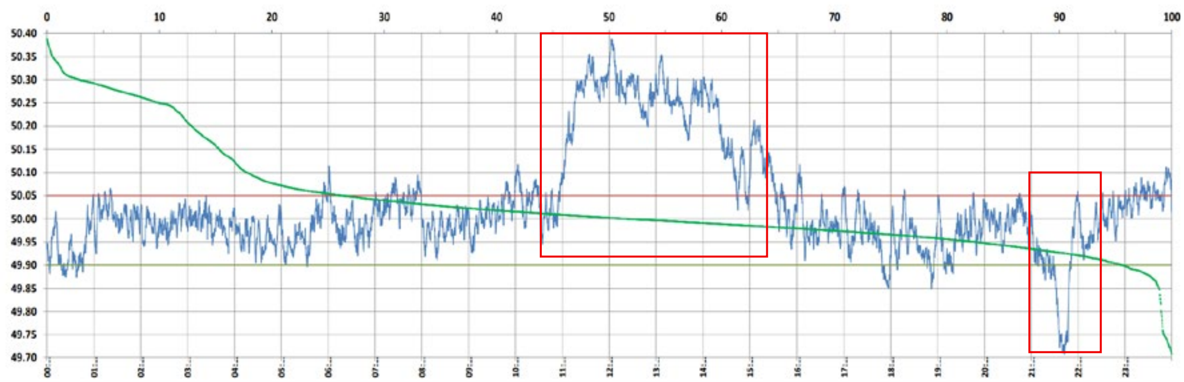

Source: GRID-India – Daily Frequency profile report

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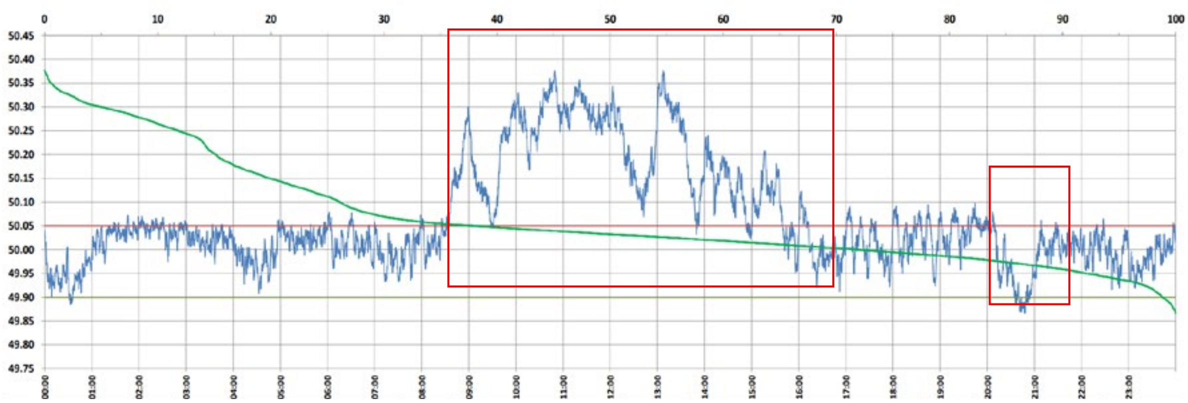

Source: GRID-India – Daily frequency profile report

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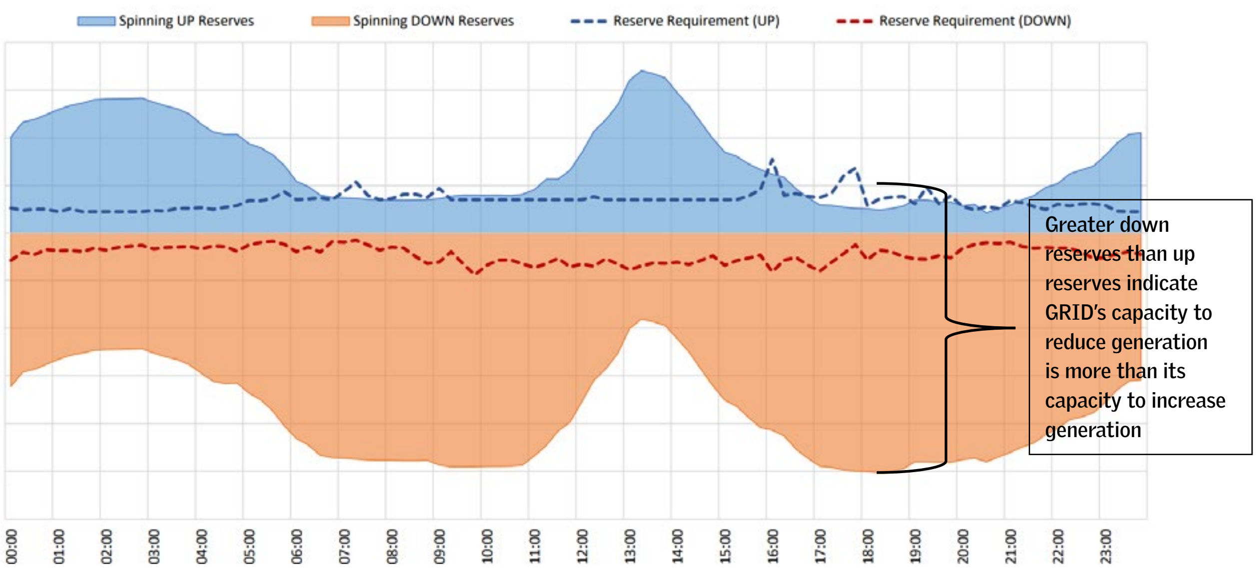

Source: GRID-India's daily report on ancillary services and Security Constrained Unit Commitment (SCUC)

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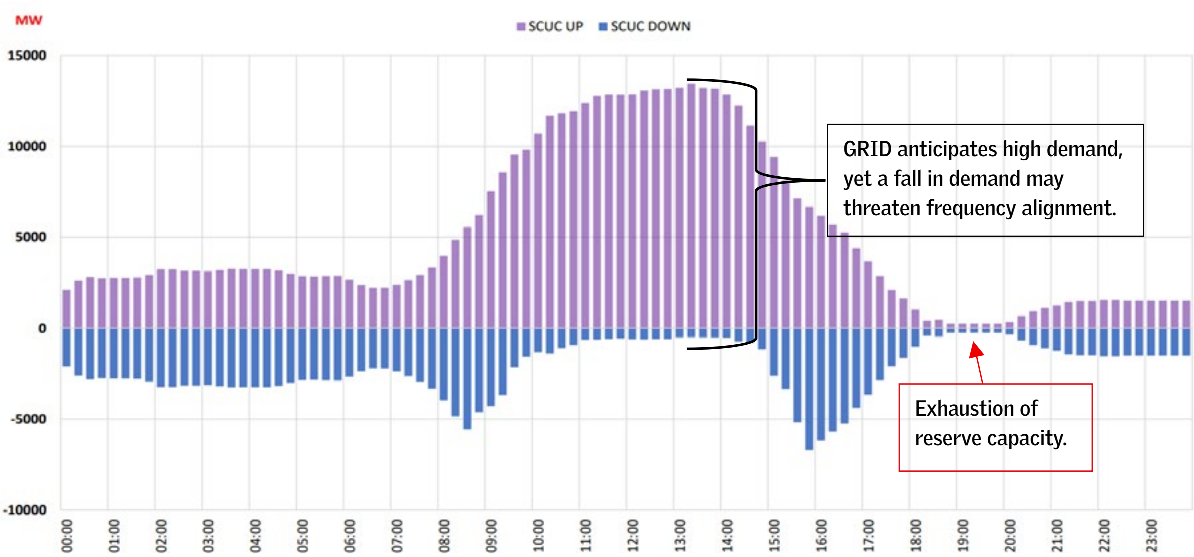


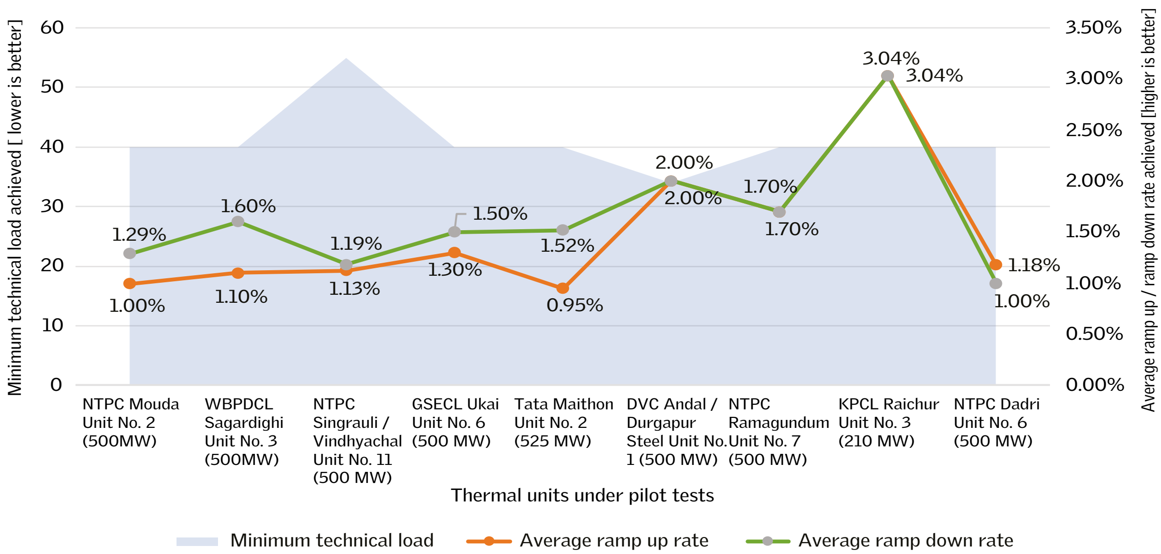
Source: GRID-India's daily report on ancillary services and Security Constrained Unit Commitment (SCUC)

Table 3: Pilot Test: Parameters for Flexible Operations

Parameters	Target
Minimum load test	40 per cent of the unit's capacity
Ramp-up test	3 per cent per minute
Ramp-down test	3 per cent per minute
Ramp-up test	1 per cent per minute
Ramp-down test	1 per cent per minute

Source: CEA Flexibilisation of Coal fired Power Plant Report, February 2023

Graph 24: Test Run Performance on Flexibilisation



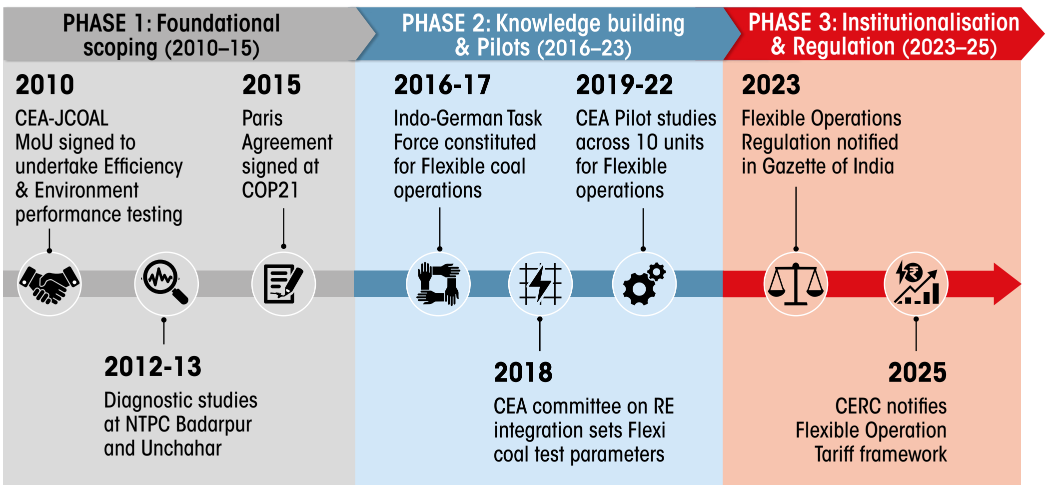
Source: CSE analysis of CEA's Flexibilisation of Coal fired Power Plant Report, February 2023 + CEA's Quarterly Review Report Renovation & Modernisation of Thermal Power Stations, July/September 2025

Table 4: Ramp Rate Requirement Under Regulations, 2023

Load Range	Minimum Ramp Rate (Up/Down) Requirement
70–100 per cent load	**≥ 3% per minute**
55–70 per cent load	**≥ 2% per minute**
40–55 per cent load	**≥ 1% per minute**

Source: Central Electricity Authority Regulations, 2023

Figure 2: Timeline of Indian Flexibilisation Policy



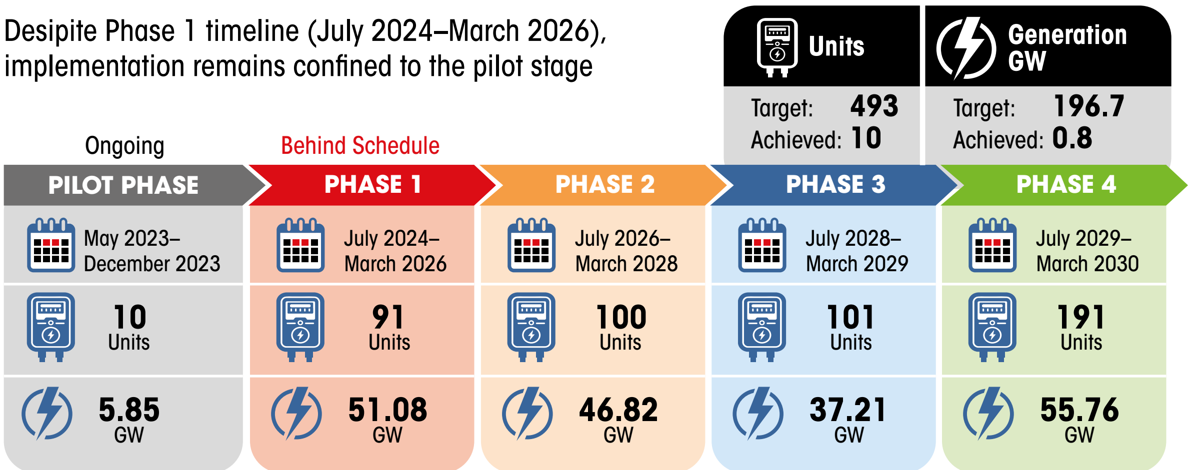
Source: CSE analysis

Table 8: India's Flexible Operation Criteria for TPPs

Flexibilisation Criteria		
Minimum Technical Load	Interim MTL threshold	55 per cent, units unable to reach 55% MTL to achieve it within one year of notification
	Target MTL threshold	40 per cent
Ramp Rate	High load range (70–100 per cent MTL)	≥3% per minute
	Mid load range (55–70 per cent MTL)	≥2% per minute
	Low load range (40–55 per cent MTL)	≥1% per minute

Source: CEA's Flexible Operation of Coal-based Thermal Power Generating Units Regulations, 2023 – January 2023

Figure 4: India: Flexibilisation Phasing Plan



Source: CSE analysis of CEA Phasing Plan, 2023

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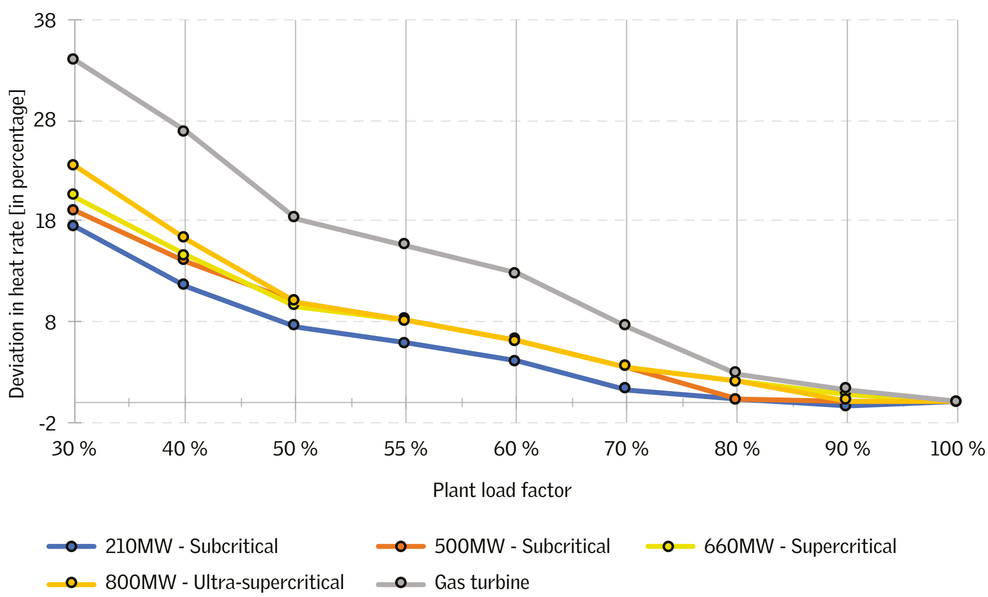


Source: CEA Roadmap for 40 per cent Technical Minimum Load

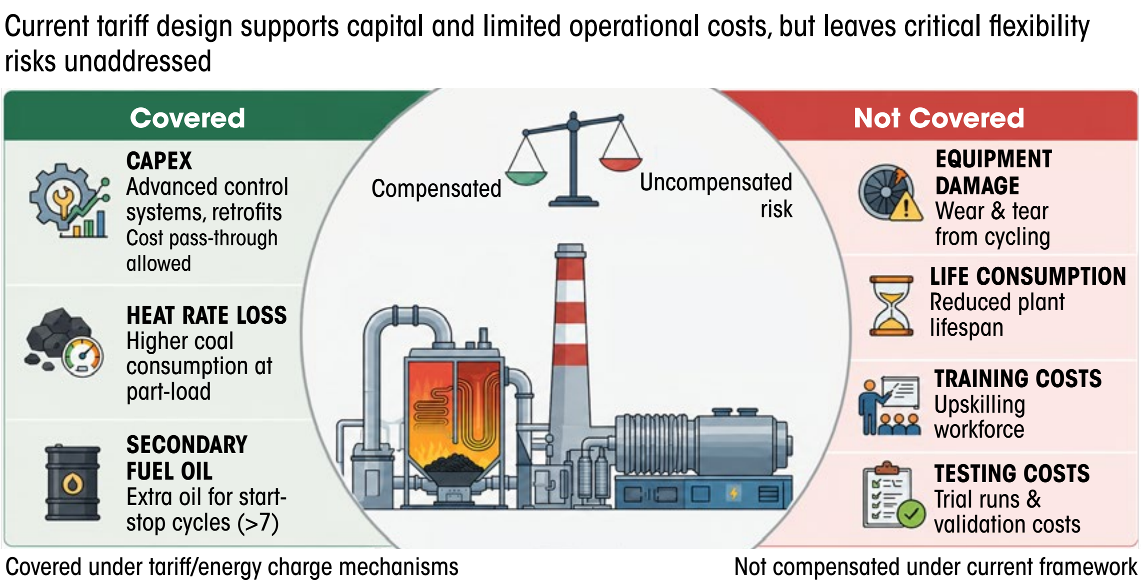
Table 6: Study-Wise CAPEX Estimates for Flexibility Retrofits

Study/Source	Plant/Scope Covered	Estimated CAPEX (per unit)
IGEF Task Force Study (2017)	NTPC Dadri (210 MW) and NTPC Simhadri (500 MW)	• Rs 3.9–7.8 crore for achieving 40% MTL • Rs 2.25–7.8 crore for start-up optimisation • Rs 0.65–1.95 crore for managing cycling-related damage
Siemens Study	NTPC Dadri and Simhadri	Rs 20–50 crore for implementing flexibility measures (advanced control, fatigue monitoring, automation, milling optimisation)
General Electric (GE) Study	NTPC Talcher	Rs 20–50 crore for advanced control system upgrades and operational optimisation measures
Engie Study	NTPC Dadri and Farakka	• Rs 3.2–5.6 crore for extended load-following at 40% MTL • Rs 4.1–8 crore for frequent warm starts
NTPC Actual Retrofit (2019)	NTPC Dadri 500 MW Unit	Rs 5.5 crore for basic flexibilisation retrofits (temperature control, milling automation, fatigue monitoring, auxiliary automation)

Source: CSE analysis of CEA reports

TARIFF COVERAGE CERC

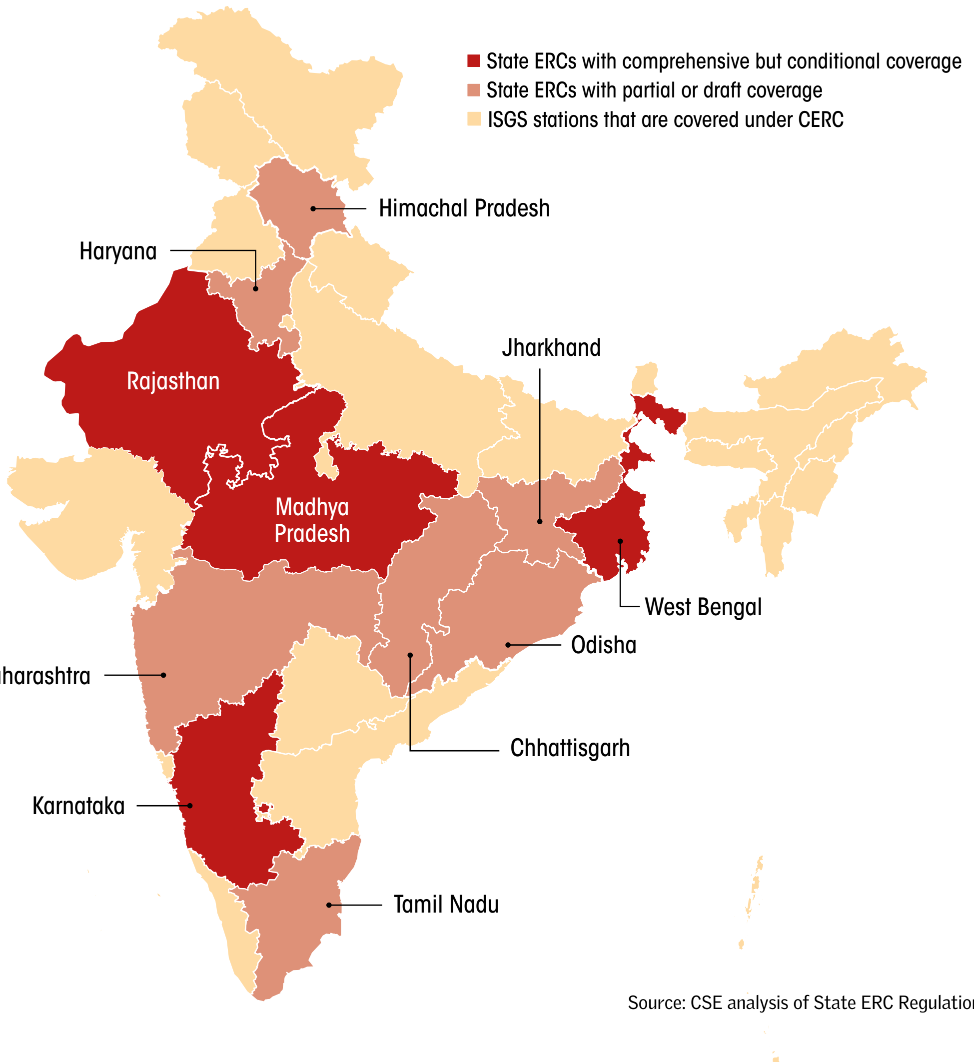
Figure 3: CERC Part-Load Tariff Mechanism



Source: CERC Regulation dated 14 July 2025

Map 1: Regulatory Coverage of Thermal Flexibility Compensation in India

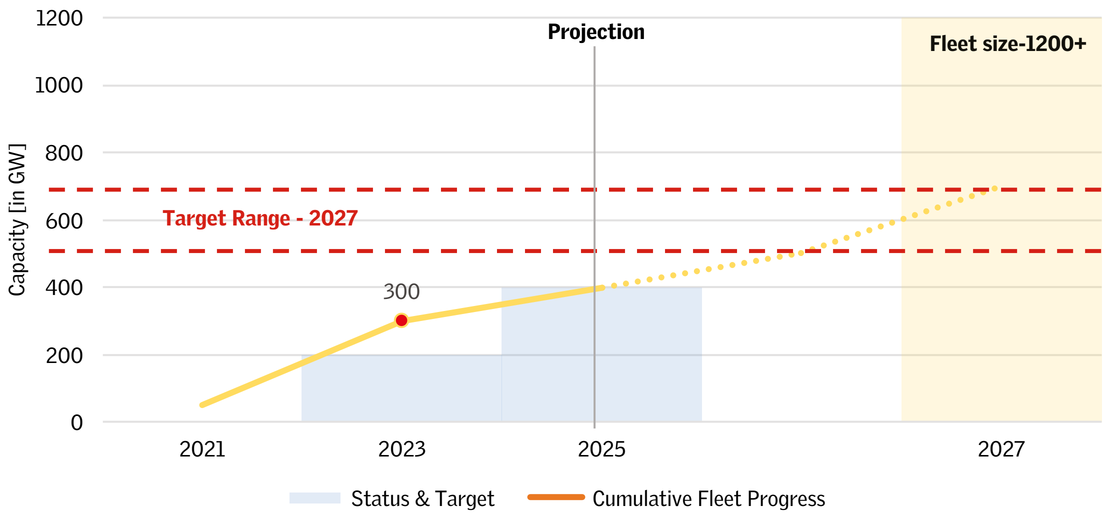
Current tariff design supports capital and limited operational costs



Source: CSE analysis of State ERC Regulations

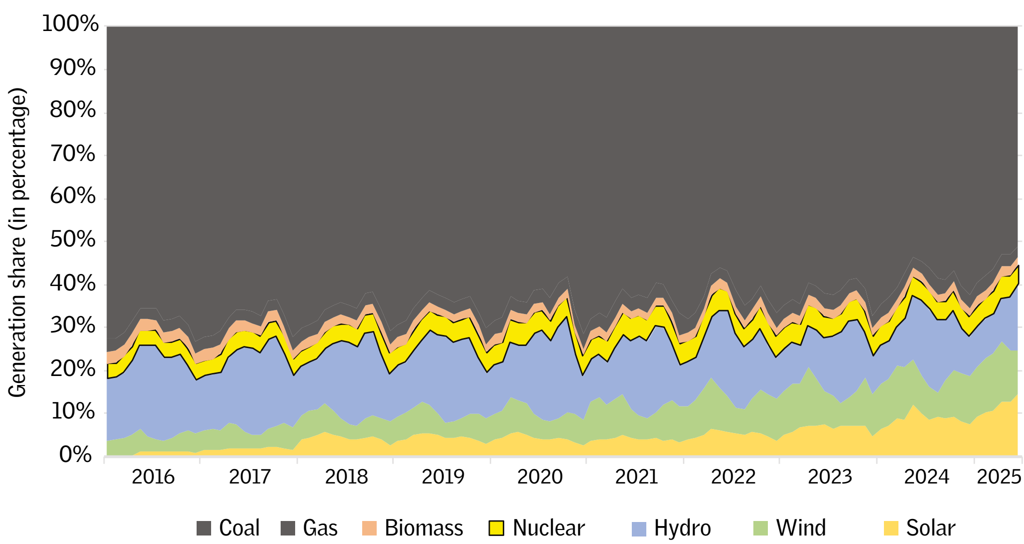
INTERNATIONAL EXPERIENCES

Graph 27: China's Coal Flexibility Retrofit Trajectory



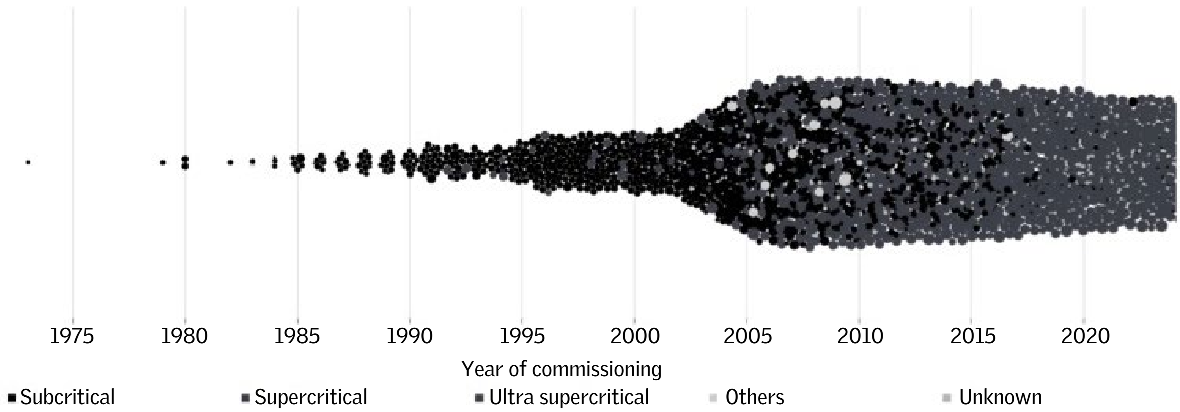
Source: CSE analysis of Chinese policy documents

Graph 28: China: Power Generation Share by Sources



Source: CREA

Graph 31: China: Age Distribution of Operation Coal Units

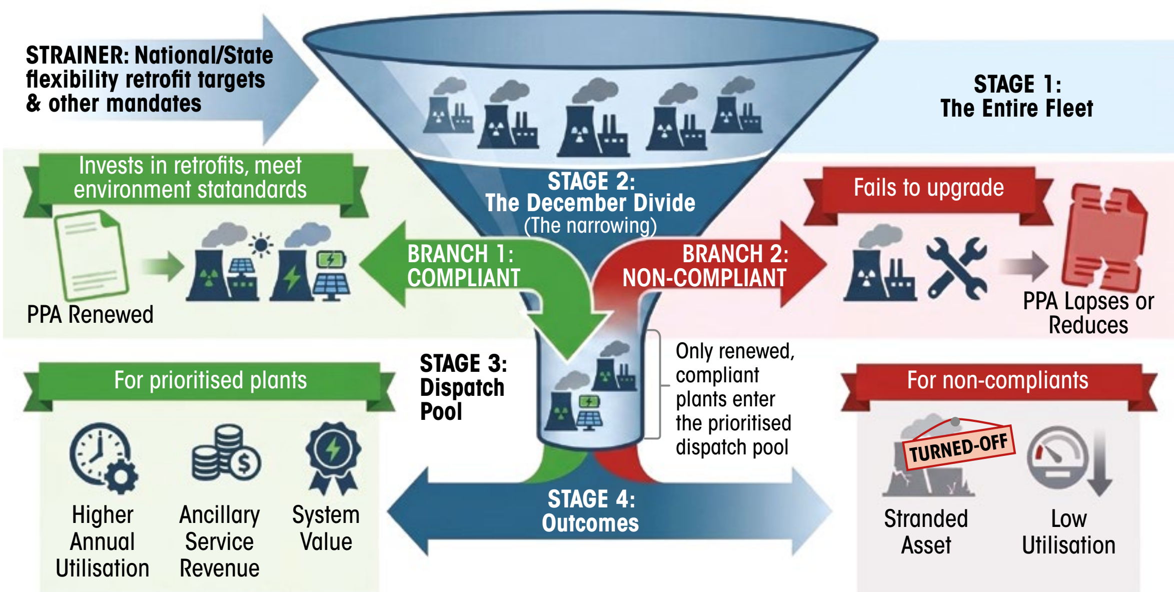


Note: size swarm-plot dot corresponds to capacity size of the operation coal plant unit

Source: Bloomberg Global Coal Countdown Dashboard

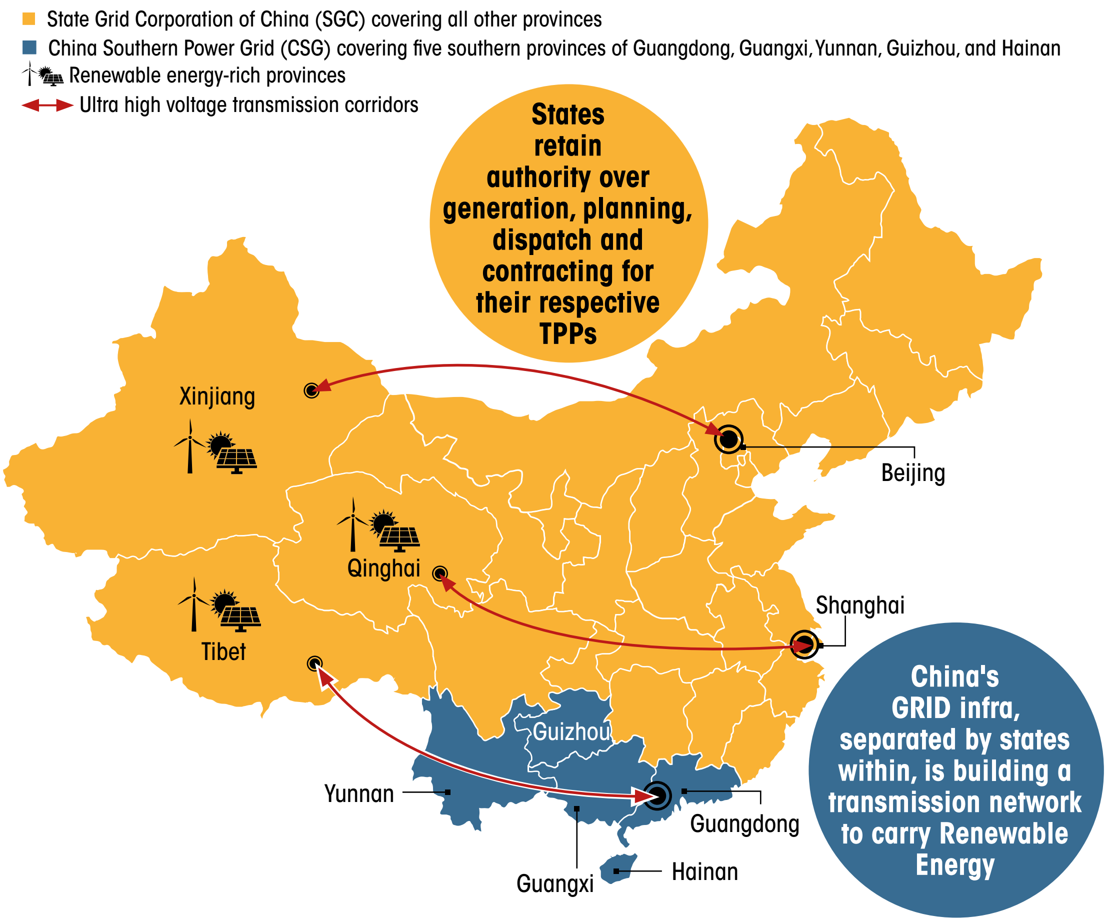
Figure 8: Chinese Policy: Funnel and Strainer System

Survival of the fittest journey for China's annual PPA compliance structure of TPPs



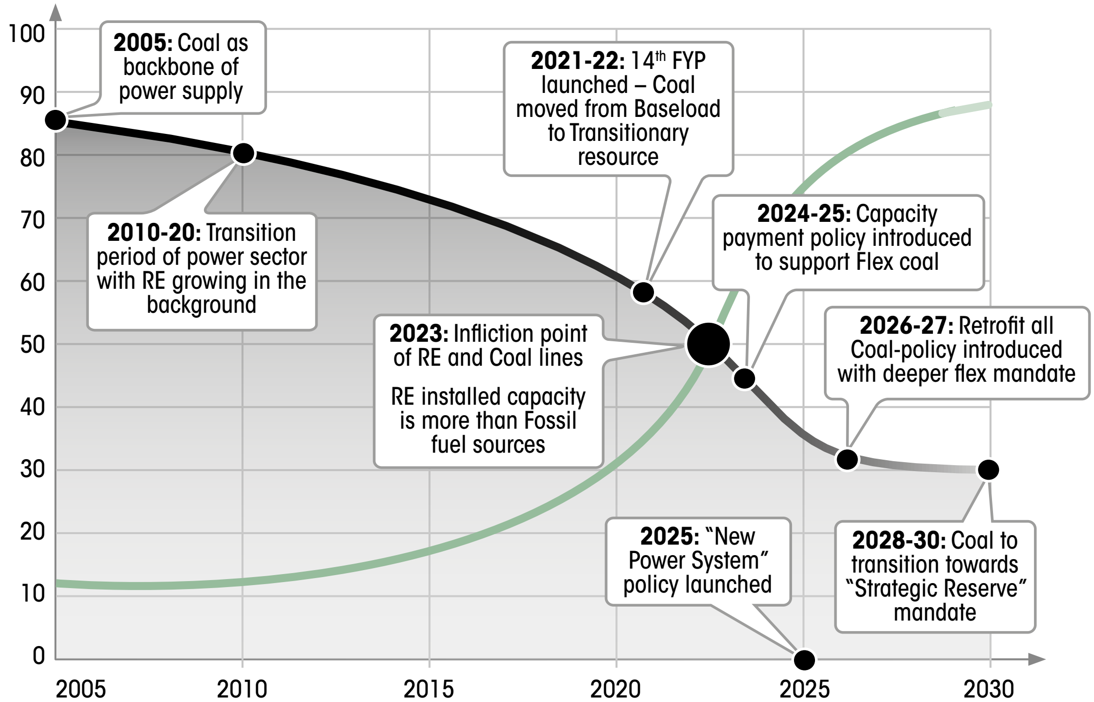
Σουρχε: ΧΣΕ αναλψσισ οφ μυλτιπλε χηινεσε πολιχψ δοχυμεντσ

Map 2: China: Power Grid and State Connections



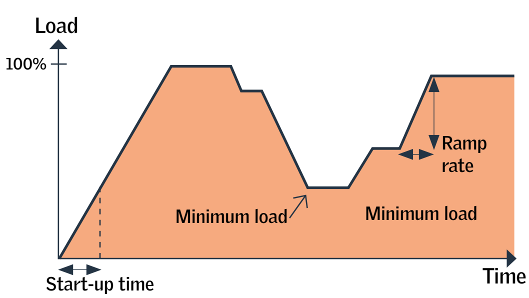
Source: CSE analysis of multiple PRC policy documents

Graph 33: China's Coal Reinvention Policy Timeline



Source: CSE analysis of multiple PRC policy documents

Figure 9: Germany: Flexibility Parameters

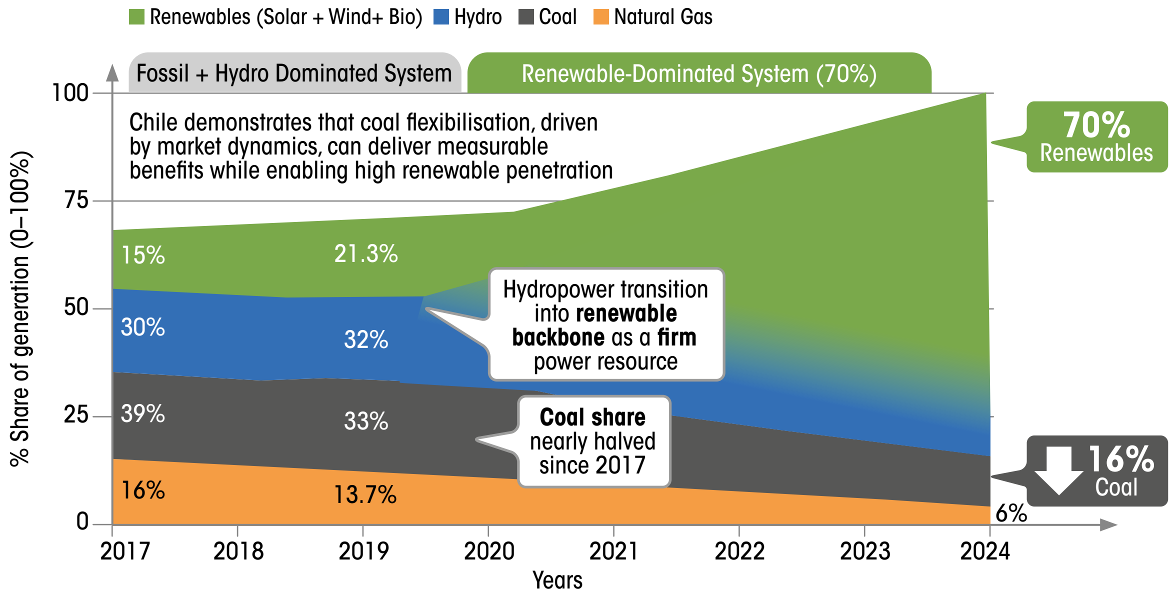


Parameter	Hard Coal	Lignite	CCGT
Ramp rate [%/min]	2 / 4 / 9	2 / 4 / 8	4 / 8 / 12
In the load range [%]	40 to 90	50 to 90	40 to 90*
Minimum load [%]	40 / 25 / 10	60 / 40 / 20	50 / 40 / 30*
Start-up time hot start < 8 h [h]	3 / 2 / 1	6 / 4 / 2	1.5 / 1 / 0.5
Start-up time cold Start > 48 h [h]	7 / 4 / 2	8 / 6 / 3	3 / 2 / 1

*Note: Conservative/state of the art/very advanced; *as per emission limits for NOx and CO

Source: Agora Energiewende

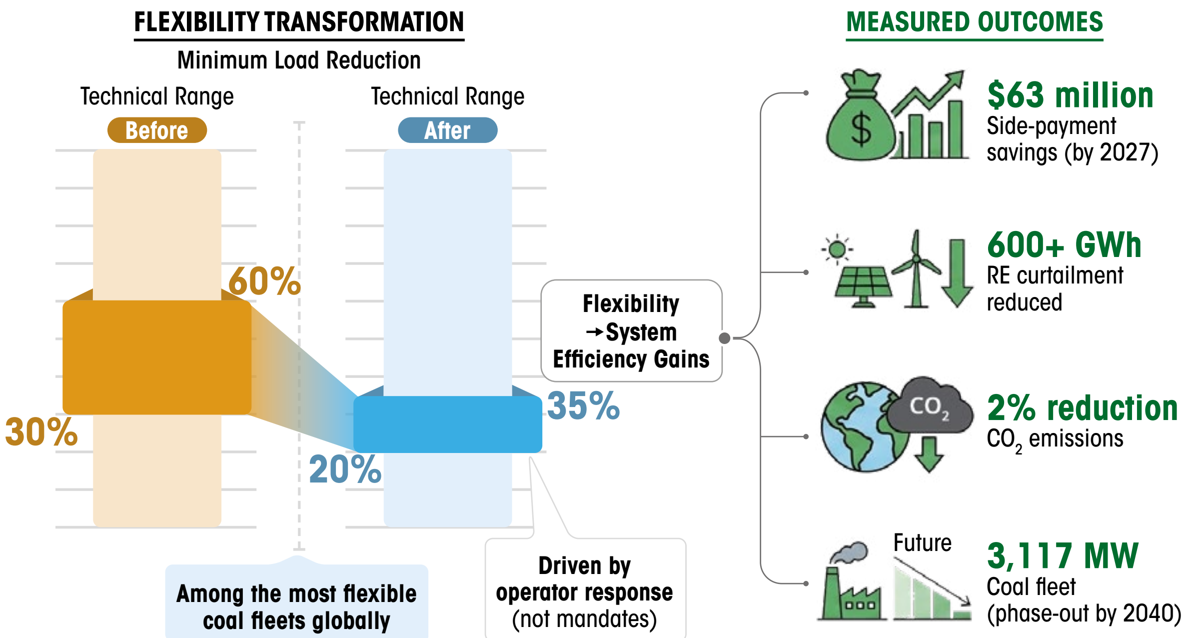
Graph 36: Chile: Electricity Generation Transition (2017 Onwards)



Source: CSE analysis of Chile policy documents

Figure 10: Chile: System-Wide Benefits of Coal Flexibility

Showcasing how flexibility policy change has delivered quantified outcomes



Chile demonstrates that coal flexibilisation, driven by market dynamics, rather than mandates, can deliver measurable economic and environmental benefits while enabling high renewable penetration.

Source: CSE illustration of GiZ's 2025 policy reports

COST ANALYSIS

Table 10: CAPEX Estimates for Flexibilisation: Coal Plant Vintage Categories

Coal Units (Based on Commissioning Date)	Suggested CAPEX (in Rs)	Scale of the Fleet Under Respective Categories Unit (Capacity in GW)
Prior to 1.1.2004	Rs 30 crore	164 (38.7)
Between 1.1.2004–31.12.2010	Rs 10 crore	75 (26.7)
Since 1.1.2011	Rs 6 crore	244 (125.4)

Source: Extrapolation of CEA's Phasing Plan, 2023 on CERC's Compensation Methodology, 2023

Table 12: Summary of Additional CAPEX for Flexibilisation Deployment

Scenario	Capacity Covered (GW)	Annual Recoverable CAPEX (Rs Cr)	Incremental Fixed Cost (Rs/kWh)	Incremental Fixed Cost (paise/kWh)
Phase I (Lower)	51.08	109.2	**0.0037**	**0.37**
Phase I (Upper)	51.08	546	**0.0185**	**1.85**
Full Deployment (Lower)	196.7	591.6	**0.0047**	**0.47**
Full Deployment (Upper)	196.7	2958	**0.0235**	**2.35**

Source: CSE analysis

Table 11: Phase-Wise Assessment of Unit-Based Coverage for State Power Corporations

S. no.	State	Power Corporation	Phase 1	Phase 2	Phase 3	Phase 4	Total
1	Andhra Pradesh	APGENCO, APPDCL	4	-	4	8	16
2	Chhattisgarh	CSPGCL	1	1	2	5	9
3	Gujarat	GSECL	-	3	-	13	16
4	Haryana	HPGCL	-	-	4	-	4
5	Jharkhand	TVNL	-	-	-	2	2
6	Karnataka	KPCL	2	-	4	6	12
7	Madhya Pradesh	MPPGCL	2	4	1	5	12
8	Maharashtra	MAHAGENCO	4	3	7	13	27
9	Odisha	OPGC	-	-	2	2	4
10	Punjab	PSPCL	-	-	2	6	8
11	Rajasthan	RRVUNL	3	2	-	4	9
12	Tamil Nadu	TANGEDCO	3	-	-	12	15
13	Telangana	TSGENCO, SSCL	7	1	2	1	11
14	Uttar Pradesh	UPRVUNL	1	1	5	13	20
15	West Bengal	DPL, WBPDC	0	2	7	4	13
Total			27	17	40	94	178

Source: CSE analysis of CEA Phasing Plan, 2023

Table 13: Proposed O&M Cost Increase Owing to Flexible Operations

Unit Size (in MW)	Operation Loading (in per cent)	Fixed Tariff Increase Due to Increased O&M Cost (in Paisa/ kWh)
200	<55 to 50	6.70
	<50 to 45	10.42
	<45 to 40	14.88
500	<55 to 50	4.57
	<50 to 45	7.11
	<45 to 40	10.16
660	<55 to 50	4.12
	<50to45	6.40
	<45 to 40	9.14
800	<55 to 50	3.70
	<50 to 45	5.76
	<45 to 40	8.23

Source: CERC Compensation Methodology, 2023

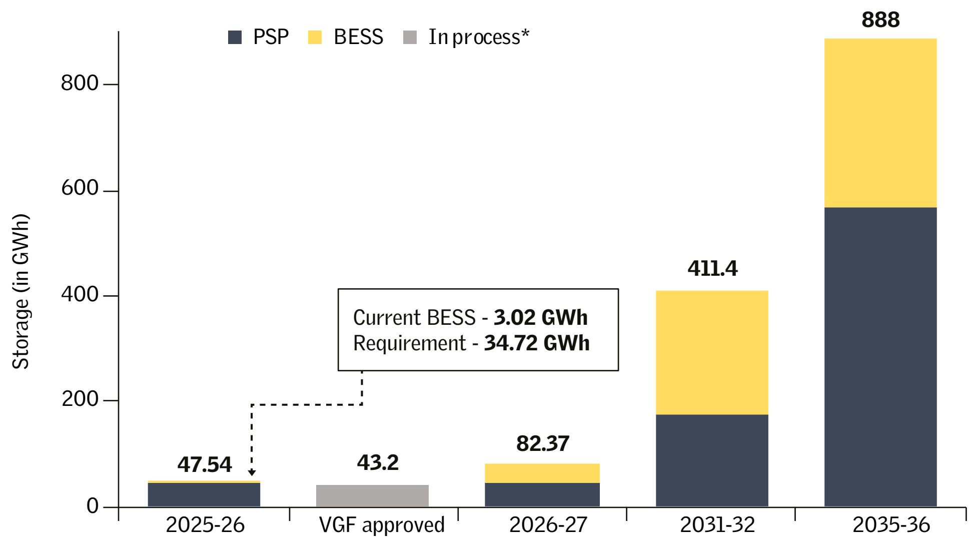
Table 15: Summary of Additional Payout Assessment Owing to Heat Rate Degradation

Scenario	Total Paid for Flexible Operations of the Entire Fleet on a Per Day Basis (in Rs crore)	Extra O&M Cost Paid for Flexible Operation on a Per Day Basis (in Rs crore)
Base (no increase)	310.8	-
+ 8.52% tariff	**337.3**	**26.5**
+ 14.86% tariff	**357**	**46.2**

Source: CSE analysis

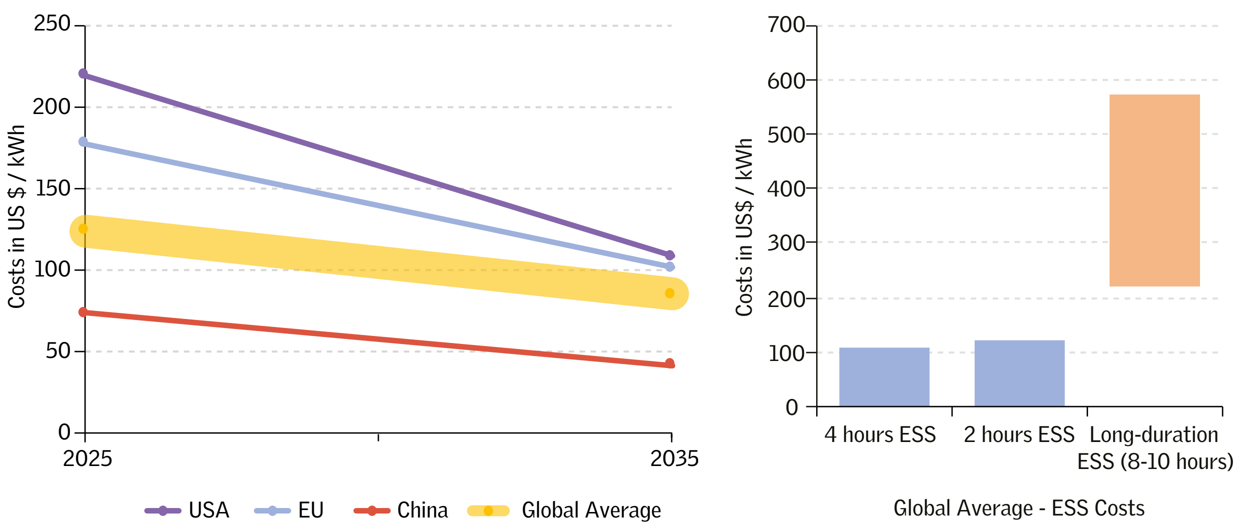
BESS AND COST

Graph 37: India – State of BESS: Requirement and Deployment



Source: CSE analysis of multiple official reports

Graph 38: Cost Trends of BESS: India and Global



Source: CSE analysis of multiple official reports

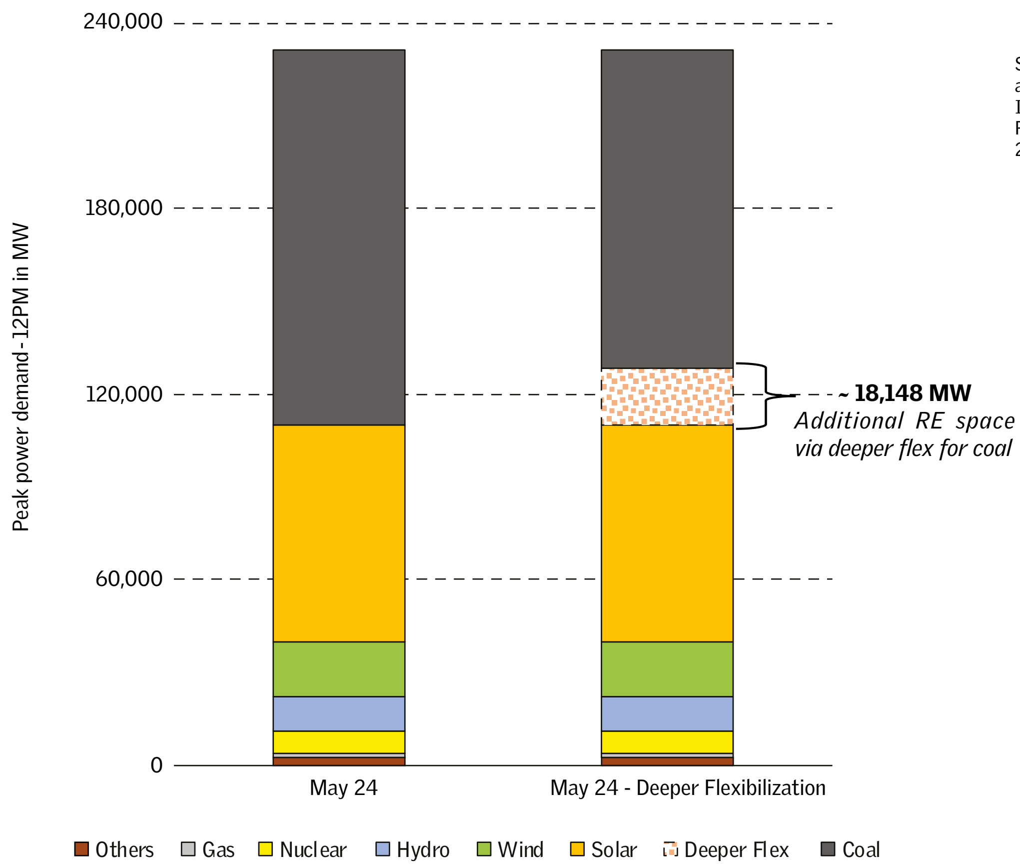
Table 16: Cost Assessment of BESS Deployment at TPPs

Storage scenario	System size assessed	Normalised cost benchmark of BESS (In per kWh)	Estimated capital requirement	Per unit cost (₹/kWh) 15-year recovery period
LDES (Current Costs)	30.8 GW/184.7 GWh	₹19,930–₹51,820	₹3.7 - 9.6 trillion (₹3.7 - 9.6 lakh crore)	₹2.7–₹7.1
LDES (Projected Costs)	30.8 GW / 184.7 GWh	₹22,100–₹32,430	₹4.1 - 6.0 trillion (₹4.1 - 6.0 lakh crore)	₹3–₹4.5
Short-Duration BESS (4-hour cycle)	30.8 GW / 123.2 GWh*	₹8,750–₹11,250	₹1.08 - 1.39 trillion (₹1.08 - 1.39 lakh crore)	₹0.8–₹1
Utility-scale BESS Tender Benchmark (NTPC Mouda)	0.4 GWh	₹12,200	₹487.77 crore	~ ₹1.1
Utility-scale BESS Tender Benchmark (NTPC Gadarwara and Khargone)	0.570 GWh	₹13,614	₹776.13 crore	~ ₹ 1.24

Source: CSE analysis

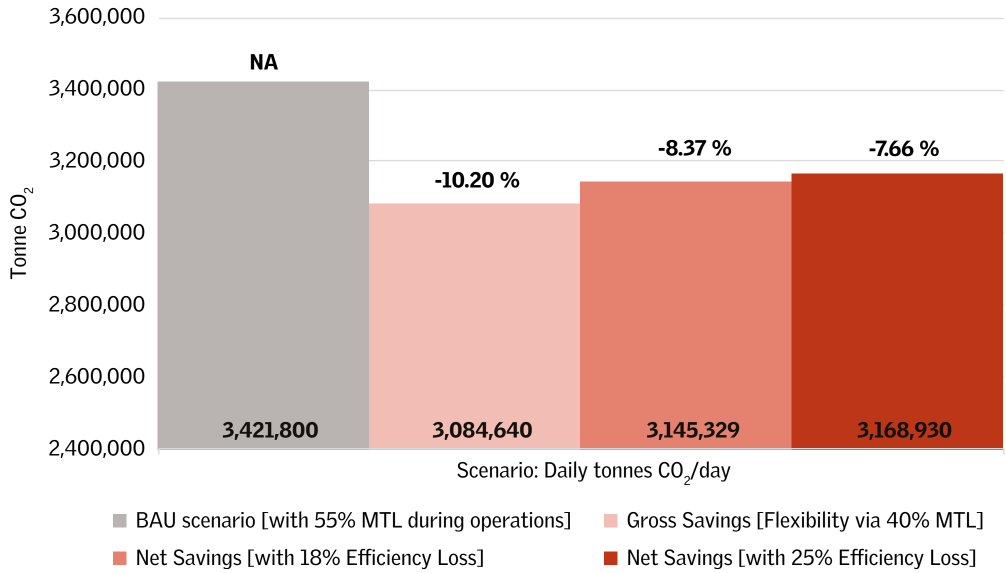
SAVINGS VIA FLEX

Graph 39: Source-Wise Generation Mix: Actual Operation Vs Deeper Coal Flexibilisation Scenario (May 24, 2026)



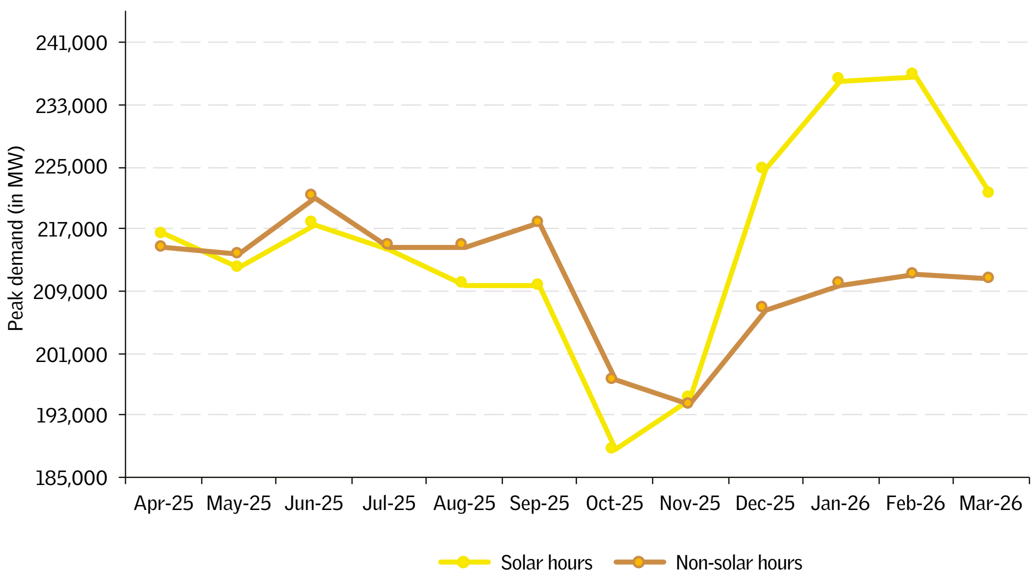
Source: CSE analysis of GRID India's Daily PSP Report, May 24, 2026

Graph 40: Daily CO_2 Saving Potential Owing to Deeper MTL



Source: CSE analysis

Graph 46: Average Monthly Peak Demand: Solar Hours and Non-Solar Hours



Source: CSE Analysis of GRID India's Daily PSP Report [FY 2025–26]

Table 17: Peak Demand and Installed Capacity (2026–27 to 2035–36)

Year	Peak Demand [in GW]	Installed Capacity [in GW]								Storage [in GW]		
		Coal (including Lignite)	Gas	Nuclear	Large Hydro	Solar	Wind	Other RE	Total	BESS	PSP	Total
2026-27*	270	237	20	10	48	176	63	17	571	6	5	11
2027-28	289	239	20	12	54	214	73	17	629	12	7	19
2028-29	305	245	20	12	55	254	83	18	687	17	13	30
2029-30	325	260	20	13	58	285	93	18	747	24	23	47
2030-31	345	276	20	14	59	320	103	19	811	28	32	60
2031-32	364	291	20	16	61	356	113	20	877	37	44	81
2032-33	388	299	20	19	64	395	123	20	940	46	54	100
2033-34	407	303	20	22	66	434	133	21	999	57	64	121
2034-35	427	307	20	22	75	474	144	21	1063	68	79	147
2035-36	446	315	20	22	78	509	155	22	1121	80	94	174

Source: CEA Long-Term National Resource Adequacy Plan (2026-27 to 2035-36)

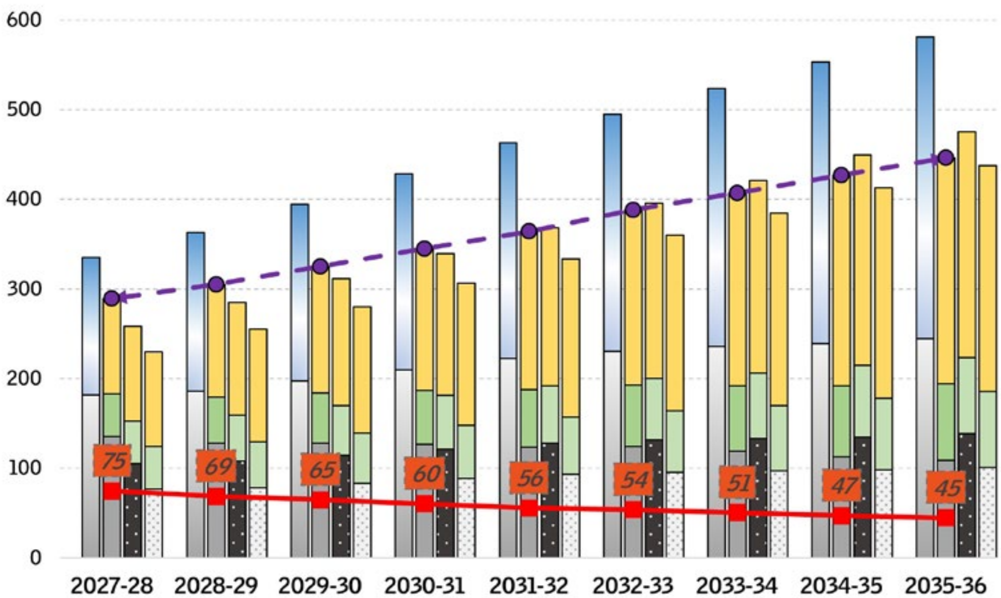
*As the current peak has already been attained on May 21, 2026 while capacity has not reached the given level, this FY has not been considered for scenario assessment

Table 18: Peak Demand Trajectories Over Scenarios (in GW)

Year	Scenario 1	Scenario 2 & 4	Scenario 3 & 5	Illustrative scenario
	Gross Peak Demand	Gross Noon Peak Demand	Gross Non-Solar Peak Demand	High RE + Low Gross Demand
	(3:30–4:00 pm)	*(11:30 am–12:30 pm)*	*(10:30–11:30 pm)*	*(3:30–4:00 pm)*
2027–28	289	268.77	268.77	*236.98*
2028–29	305	283.65	283.65	*250.10*
2029–30	325	302.25	302.25	*266.50*
2030–31	345	320.85	320.85	*282.90*
2031–32	364	338.52	338.52	*298.48*
2032–33	388	360.84	360.84	*318.16*
2033–34	407	378.51	378.51	*333.74*
2034–35	427	397.11	397.11	*350.14*
2035–36	446	414.78	414.78	*365.72*

Source: CSE analysis of CEA Long-Term National Resource Adequacy Plan (2026-27 to 2035-36)

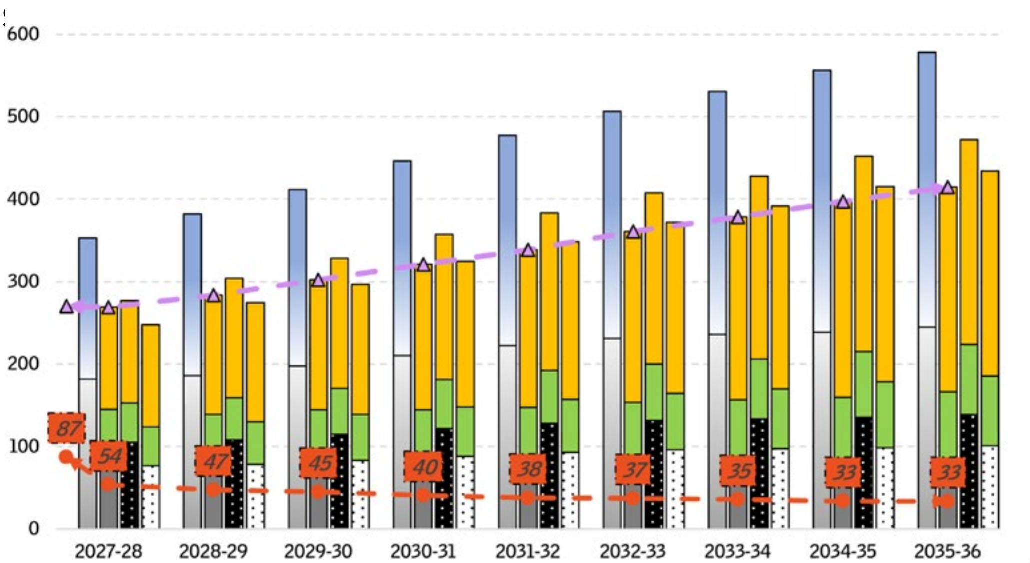
Graph 41: Scenario 1: Gross Peak Demand Estimation (3:30–3:45 pm)



Legend: On capacity RE, On capacity Coal, Available RE, Available Solar, Locked-in Coal (55% MTL), Locked-in Coal (40% MTL), Peak Demand, Requisite Coal PLF

Source: CSE analysis

Graph 44: Scenario 4: Gross Noon Squeeze Demand Estimation with Storage on



Legend: On capacity RE, On capacity Coal, Available RE, Available Solar, Locked-in Coal (55% MTL), Locked-in Coal (40% MTL), Peak Demand, Requisite Coal PLF

Source: CSE analysis

FINDINGS OF THE REPORT

The report highlights several key findings that underscore the growing need for flexibilisation in coal-based thermal power plants. They reveal the emerging systemic, structural, and policy gaps within the regulatory ecosystem that has strained the implementation of flexible operations across India. They establish flexible operation as an operational necessity of the country's evolving power system, not merely a technical option.

I. **Daytime solar penetration is rising:** India's installed solar capacity has grown by **90 GW** over the past six years, with non-fossil fuel capacity now surpassing fossil-based capacity. This has led to a sharp rise in daily solar energy penetration, with daytime solar penetration increasing by **67 per cent** since 2020. With 93 GW of solar capacity currently under construction, the system-wide requirement for integration is expected to roughly double in the coming years.

II. **Power system ramping requirements are rising rapidly**: The widening gap between peak and lean demand, exceeding 70 GW within a day in 2025, has significantly increased system's ramping requirement. Thermal plants must now adjust output more frequently to maintain real-time supply–demand balance, grid frequency and increasing renewable penetration. System-level ramping requirements have already reached about 250 MW per minute and are projected to rise to **380–420 MW per minute** under high renewable penetration scenarios, indicating growing dependence on flexible thermal generation for grid stability.

III. **Deepening duck curve necessitates lower minimum technical loads for thermal plants**: Rising solar generation is producing sharp midday reductions in net load for thermal plants followed by steep evening ramps. During solar peak hours, thermal units are already operating near their minimum technical load, limiting their ability to reduce generation further. Without lowering MTL thresholds through enhanced flexibility, additional solar output will increasingly be curtailed to maintain grid balance. As solar penetration continues to rise, expanding thermal flexibility by enabling deeper ramp-down capability becomes essential to prevent large-scale daytime renewable curtailment.

IV. **Grid stability risks due to thermal fleet constraints led to frequency mismatch events:** Recent high-frequency episodes of 4, 11, and 25 August 2024 examined by CERC exposed the grid's limited ability to respond to thermal over-injection, greater RE generation, and sudden fall in power demand. Current thermal minimum load constraints with fleet limited to 55 per cent MTL drove sustained frequency deviations and has subsequently led to RE curtailment for grid stability management. The events reflected coordination gaps across scheduling, dispatch, and market mechanisms, alongside insufficient downward reserves and limited real-time balancing capability highlighting the structural mismatch between system requirements and thermal operating capability, particularly during solar hours.

V. **Rising RE curtailment increasing economic and climate burden:** Renewable energy curtailment is increasing, as system flexibility struggles to keep pace with solar expansion. Grid interventions show large episodic curtailment, including 45 GWh on a single day and over 93 GWh during peak stress events. Between April 2025 and March 2026 alone, about **7,136.39 GWh** of solar and **486.99 GWh** of wind generation were curtailed. This led to added economic burden of Rs 2,651.32 crore as shadow cost of unused RE and Rs 3,331.42 crore as the replacement cost of fossil fuels, resulting in a total economic burden of **Rs 5,982.74 crore in 2025–26.** Additionally, this resulted in **approximately 7.91 MT of avoidable CO_2 emissions**. These growing volumes reflect structural limits in capability, reserve provisioning, and storage availability, underscoring the urgent need for enhanced thermal flexibility.

VI. **Thermal Flexibility Unlocks Multi-Gigawatt Space for Immediate RE Integration:** Compressing the MTL of India's coal fleet from 55 per cent to 40 per cent during 10 solar-rich daytime hours creates an immediate, system-wide operational headroom of **34.275 GW**. On a day-to-day operational level (as modelled on a typical peak demand day), this deep-flexing framework creates approximately ***18,148 MW of additional real-time grid absorption space***. This structural capacity relief effectively allows the grid to accommodate 25 per cent more solar generation or completely double its wind integration during critical midday windows without risking baseload over-generation.

VII. **Deep Turndown Operation Yields Net Decarbonisation Gains Despite Fleet Efficiency Penalties:** Sustained low-load thermal operations trigger significant heat rate deterioration, increased auxiliary consumption, and sub-optimal combustion performance, resulting in a technology-wide efficiency penalty ranging between 18 per cent and 25 per cent. However, the counter-factual modelling proves beyond reasonable doubt that the clean energy replacement benefit vastly outpaces these performance losses. Lowering the fleet's operating floor to 40 per cent delivers a net annual environmental dividend, avoiding **between 92 and 101 million tonnes of CO_2 emissions**. Thus, creating a *net fleet carbon footprint reduction of 7.66 per cent to 8.37 per cent on a daily basis*.

VIII. **Rapid Battery and Pumped Storage Scaling Cannot Substitute for Long-Term Fleet Flexibilisation:** While integrating a massive, projected national energy storage portfolio (scaling from 19 GW in 2027–28 to 174 GW by 2035–36) provides an essential midday charging sink and mitigates severe evening ramping strains, it does not solve the structural rigidity of the conventional fleet. Because massive solar capacity additions continue to depress the required daytime PLF of coal year-over-year, RE curtailment remains structurally inevitable if the legacy fleet stays bound to a rigid 55 per cent MTL baseline. Storage expansion and aggressive thermal floor compression must be mandated in tandem to achieve permanent grid balance.

IX. **Costly gas is bridging peak demand surges:** India's evening demand surges, coinciding with rapid solar decline, are increasingly met by gas-based generation due to limited ramping capability in coal plants. For instance, assessment of demand on April 23, 2025 highlights a rise in demand from 213 GW to over 224 GW within an hour, while solar output collapsed from nearly 19.4 GW to under .3 GW. With coal ramping constrained, gas generation increased by 6–8 per cent in each 15-minute block despite high costs of Rs 12–12.57 per kWh, reflecting the system cost of inadequate thermal flexibility. Therefore, these demand surges are being met with double economic outlay than coal or RE to provide for required power demand.

X. **Pilot studies confirm technical feasibility for flexibilisation:** CEA's pilot flexibilisation studies have demonstrated capability of Indian coal units to operate flexibly. Majority pilot units achieved the 40 per cent minimum load target and DVC's Andal unit operating even lower. Ramp rate tests confirmed performance ranging from baseline 1 per cent per minute to over 3 per cent per minute in select units. These results provide empirical evidence of technical feasibility while underscoring the need for targeted retrofits and unit-specific operational modifications.

XI. **Tariff recognition of flexibility costs remains partial:** Flexible operations have financial implications requiring CAPEX and continuous operational costs impacting equipment life. The CERC has recognised the same via separate regulatory framework, yet significant gaps in elemental coverage remain limited resulting in ineffective implementation. The CERC mechanism allows recovery of CAPEX via consumer pass-through, along with selected operational impacts such as heat rate degradation and additional secondary fuel consumption. However, **lifecycle impact costs on plant equipment are not covered**, largely due to the difficulty of attributing future damage, specifically to flexible operations rather than routine operational issues. In addition, several transition-related expenses, including workforce upskilling, testing and commissioning, enhanced grid and scheduling coordination, and broader system integration requirements, remain outside existing compensation frameworks. Moreover, tariff mechanisms typically rely on **averaged operational parameters**, which may not fully capture the real-time costs associated with flexible plant operation.

XII. **Regulatory gaps and centre-state misalignment slows flexibilisation**: The current regulatory framework creates uneven incentives across different categories of power plants. Flexibility compensation currently applies primarily to cost-plus generating stations, while competitively bid plants generally lack comparable cost recovery mechanisms despite being subject to similar operational requirements. Regulatory approaches also vary widely across states, with some regulators relying on simplified norms or state-specific methodologies rather than standardised, formula-based compensation mechanisms. Adoption of flexibilisation regulations remains uneven; only five states have issued formal provisions recognising flexibilisation costs cover leading to significant non-coverage of the coal fleet. This regulatory asymmetry leaves a large portion of the coal fleet without adequate policy support, creating uncertainty for plant operators and slowing the broader adoption of flexible generation practices.

XIII. **China showcases ambition and policy enforcement of a far steeper scale**: China has successfully transitioned their 1.1 TW coal fleet beyond baseload operation, allowing their power generation mix to contain 50 per cent RE. Having started similarly to India in 2016, their target for flexible operation is to operate the fleet at technical loads of 25 per cent. Post 2021, with a decisive national push, they have transitioned over 300

GW of coal fleet with aggressive retrofits to achieve new minimum load targets. Their current target, updated in 2025, is on course to retrofit their entire coal fleet to operate between 25 to 40 per cent technical load. The rapid execution is driven by binding administrative levers, including performance-contingent PPA renewals on an annual basis. Their model integrates a capacity payment system to aid coal units in their economic viability owing to falling utilisation factor as renewables surge in the power grid. China's model ensures that access to state-directed capital is strictly contingent on retrofit execution, transforming national Five-Year Plan objectives into enforceable investment decisions.

XIV. **BESS not yet scaled for system needs**: As of 2025, India's operational BESS capacity remains limited at 205 MW (0.5 GWh). The sector is primarily focused on short-duration storage (two to four hours) for solar shifting and grid stability, while LDES is currently in the R&D phase. To accelerate growth, in 2025, the Union Ministry of Power approved a VGF scheme for 43.2 GWh of BESS. Currently, India targets to reach 236.22 GWh by 2030 and 1840 GWh by 2047, which will require acceleration and a gestation time looking at the current deployment numbers. The challenge of global supply chain and the need for high capital cost will have to be navigated for accelerating deployment.

XV. **Battery storage at coal plants is prohibitively costlier**: Replacing thermal ramping with battery storage at coal plants would require roughly 30.8 GW/184.7 GWh of battery capacity, implying investment of Rs 3.7–Rs 9.6 lakh crore for long-duration systems or Rs 1.08–1.39 lakh crore even for short-duration deployment. This translates into a per unit fixed cost recovery in the range of Rs 0.8–Rs 7.1 over 15-year period. On a CAPEX level, the expenditure is roughly 600 per cent–31,000 per cent higher than flexibilisation expenditure. Directing investment toward thermal-linked storage risks diverting scarce transition capital away from renewable integration and system optimisation priorities. Also, with limited duration storage capacity, the challenge of constantly fluctuating demand will remain unaddressed.

XVI. **Flexibilisation is a financially moderate:** Cost assessment shows that flexibilising India's 199.4 GW coal fleet requires capital investment of roughly **Rs 2,898–Rs 14,490 crore**, with tariff impacts limited to about **0.47–2.35 paise/kWh** under phased recovery. Even when accounting for operational degradation, system-level cost increases remain incremental rather than structural, with daily tariff increase remaining between 8–15 per cent. This demonstrates that flexible thermal operation can deliver balancing capability at manageable financial cost within existing tariff frameworks, making it an economically viable near-term instrument for renewable integration.

XVII. **Flexibility follows incentives, dispatch control and policy consistency:** Experience from China and Germany shows that thermal flexibility scales when incentives, dispatch rules, and long-term policy direction move in alignment. Binding planning frameworks, consistent policy signalling, and coordinated financial support sustain implementation momentum over time. China enforces it through performance-contingent contract renewals, where non-compliant units lose market access, and discretionary dispatch that rewards flexible units with higher utilisation while Germany leverages market maturity, using 15-minute trading blocks and price-based dispatch to provide clear financial rewards for rapid responsiveness. Together this demonstrates that flexibility adoption depends not only on technical capability but on durable institutional commitment and aligned system-wide incentives.

XVIII. **Implementation of India's flexibilisation plan lags behind despite AGC expansion:** Implementation of the phasing plan remains slow relative to regulatory timelines. Of the 513 units (199.4 GW) targeted, only **one unit has fully achieved both** 40 per cent MTL and ramp-rate compliance, with about 1.9 GW demonstrating low-load capability without full ramping validation. Even the pilot phase remains incomplete. In contrast, AGC has scaled to **72.3 GW across 144 units.** This highlights faster progress in grid-level system update than plant-level flexibility related retrofitting.

XIX. **Renewable energy currently lacks grid-forming capability:** India's power system continues to rely on conventional thermal plants to provide inertia, voltage regulation, and frequency stabilisation. Most renewable generation is grid-following and cannot independently support system frequency or provide rapid stabilisation during disturbances. Until grid-forming inverters or large-scale battery energy storage systems are deployed at scale, this gap in frequency-support capability will persist.

POLICY RECOMMENDATIONS

India's drive to meet its climate goals while ensuring a reliable energy supply necessitate a transition towards adapting the existing power generation capacity to accommodate greater renewable energy injection. Even though the current scale of RE, is well below the future capacity plan, it is suffering from curtailment on a regular basis. The situation is therefore untenable and requires definite addressal. The report has identified the scale of flexibilisation required for the current coal-based thermal capacity. The stakeholders' role ought to be aligned in conjunction of one another for the necessary uptake of flexibilisation across the current coal fleet. Based on the current status of flexibilisation in 2026 and aligning it with CEA's phasing plan, CSE proposes policy actions for the concerned stakeholders to accelerate the implementation mechanism.

Recommendations for Central Regulators

I. **Factors for reconsideration and prioritization in the Phasing plan:** The CEA's phasing plan is the bedrock of flexibilisation implementation in India. However, to ensure a functional and cost-effective transition, the current plan ought to reconsider its prioritisation of listed units based on systemic, technical, and economic factors with an evidence-based deliberation. Factors for consideration are:

- *Heat-rate and Emission performance:* While thermal units face an SHR degradation in the range of 18 to 25 per cent during flexible operations, supercritical / ultra-supercritical units maintain a lower baseline emission factor than subcritical units. There is a need to clearly identify the SHR degradation and CO2 emission during sustained low-load operations in all three technologies, as there is variance in inputs from different stakeholders. Incorporating emission performance and unit degradation into unit prioritisation of the phasing plan will help minimise the overall emission impact, aligning the outcome of flexible operations with larger decarbonisation benefits.
- *Consideration of greater utilisation of efficient and low-emission assets:* Modern ultra-supercritical and supercritical units have been built with high capital expense and are largely under-utilised owing to the rules of Merit Order Dispatch. The rules advantage old subcritical units with lower efficiency, resulting in a slow bleed of the high capital investment into new thermal units. The suggestion is that the phasing plan can incentivise greater utilisation of supercritical and ultra-supercritical units for overall lower systemic emissions.
- *Consideration of two-shift operation for old and inefficient plants:* The cost of retrofitting old and inefficient units / beyond operational life (greater than 30 years of age), will be high, and they may not even have the lifespan left to recover these costs. These units at low-load operations may be at a greater

risk of tripping and thus be an unreliable source of flexibility for the system. These units may be reserved for non-regular usage, during seasonal loads and limited peak meeting support roles or two-shift operations to avoid further capital infusion in their operations.

- *Technological limits of thermal units:* The technology of a thermal unit determines the scale, performance and the cost of retrofitting for flexible operation. For instance, industry inputs state that supercritical and ultra-supercritical units do not possess steam drums and face specific technical constraints around the “Benson point”, necessitating a safety margin of at least five per cent above the MTL during operations. Furthermore, while the O&M tariffs for flexibility consider additional oil consumption, the time variance in start-up is critical to the grid’s planning for power generation. Usually, the start-up time of subcritical units is generally around eight hours, while supercritical / ultra-supercritical units typically require up to 30 hours and incur significantly higher oil consumption. Ignoring the technological constraints of units within the plan will result in a sub-optimal realisation of the system performance of flexible operations, reducing the gains of flexibilization.

CSE recommends that these factors be formally assessed to weigh up and restructure the overall phasing plan. Before a final restructuring is implemented, a detailed evaluation of technological limits, startup economics, and real-time emission profiles is essential for the plan to be functional.

II. **Undertake unit health baseline study for life cycle impact costs:** Currently, regulators (CERC/SERCs) exclude expected life cycle impact costs from compensation due to ambiguity regarding future wear-and-tear. To resolve this, a structured baseline health assessment should be mandated for all units prior to each implementation phase. Establishing an initial *‘health signature’* allows regulators to distinguish between legacy degradation and flexibility-induced damage. The transparency enables evidence-based damage attribution, providing a credible foundation for regulators to authorise the recovery of flexibility-related operational costs.

III. **Strategise power system flexibility based on cost competitiveness**: CSE’s assessment highlights the significant capital costs associated with deploying BESS at thermal plants, alongside concerns of increased fossil-linked emissions and the potential crowding out of investment from BESS deployment in renewables, especially with the challenge of import dependence and rising global trade curbs. In the current scenario, the higher fixed costs of BESS at thermal vis-à-vis flexibility retrofits, may also show upfront in the already rising electricity costs thereby increasing the cost burden on end consumers, therefore strategic selection of power flexibility pathways needs to be done based cost competitiveness as well as increasing clean energy in the grid. The cost dynamic ought to be transparently reflected in the MOD, with scheduling and daily generation determined accordingly. This will enable an evidence-based assessment of cost competitiveness and may reveal BESS's limited viability as a cost-effective system solution relative to flexibility retrofitting.

IV. **Integrate flexibility costs into future investment decisions:** With renewable energy capacity expanding rapidly and altering the role of coal power, India's future capacity additions ought to be explicitly aligned to the dynamic nature of power system going ahead. India's rising demand must be met with a least cost generation source. The choice of resource to meet future demand needs to be cost-sensitive. Hence, it needs to be considered that any upcoming coal capacity will have an additional cost of flexibility passed onto the consumers. Inflexible coal investments risk creating underutilised assets and stranded cost burdens due to lower utilisation factors, especially with continuation of long-term PPAs. Policy frameworks should therefore explicitly account the elemental costs of evolving system needs.

V. **Standardise curtailment cost disclosure:** Regulatory reporting should incorporate a uniform and transparent accounting of the financial and environmental costs associated with renewable energy curtailment. At present, these impacts remain fragmented across system actors, such as RLDCs and state level DISCOMs, weakening their visibility in planning and dispatch decisions. Establishing standardised disclosure frameworks will improve institutional signalling, enable evidence-based investment prioritisation, and support policy alignment toward reducing system inefficiencies and avoidable emissions. Additionally, the absence of such disclosure frameworks risks obscuring these system-level costs, which are expected to rise with increasing renewable energy penetration, thereby undermining their visibility in planning, investment, and policy decisions.

VI. **Operationalise ToD pricing with market-linked dispatch:** Power system operations should increasingly align with ToD price signals, enabling dispatch to reflect real-time system value rather than static scheduling. TPPs, particularly for their un-requisitioned capacity, should be allowed to participate in market-based operations akin to captive generators, supplying power during high-price periods, such as peak demand hours or at night when market prices are elevated, creating competitive operational structure. Participation in this mechanism will inherently require a unit to be flexible. Embedding ToD pricing within dispatch frameworks will incentivise flexible generation behaviour, and ensure that system costs and efficiencies are transparently reflected in scheduling decisions.

VII. **Broaden compensation framework and testing schedules**: To accelerate fleet readiness, regulatory frameworks must recognise the full economic and operational costs of the transition to flexibility. This requires incorporating training and testing expenses into CAPEX structures and adjusted fixed-cost tariffs, ensuring these "invisible" costs are recoverable. Simultaneously, system operators under GRID-India, ought to provide designated scheduling windows and transmission headroom specifically for ramp testing and workforce familiarisation. By aligning financial compensation with structured operational allowances, regulators can reduce implementation uncertainty and enable capacity-building without compromising grid stability.

VIII. **Establish incentives for complying units:** The current policy lacks incentives for generation units to undertake flexibility. As all power units fulfil the basic requirement of energy generation, penalising non-compliance is beyond the core object of the generation unit. Thus, creating incentives, such as preference in MOD and greater generation preference ought to be established into the policy for greater uptake. The Chinese model of lump-sum payouts for complying units can be considered to greatly incentivise the uptake of flexibility by individual generation units.

IX. **Fund and strengthen grid system operator capabilities:** Flexibilisation significantly increases dispatch complexity, real-time monitoring requirements, and coordination across scheduling layers. Load despatch centres must therefore be aided in adapting their analytical, simulation, and operational capabilities to manage evolving system dynamics. Simulator training programme for operators ought to be pursued. Regulators should recognise investments in workforce training, simulation platforms, and analytical decision-support tools for load despatch centres as eligible system costs, enabling operational capacity to evolve alongside generation flexibility requirements.

X. **Inventorise and report fuel quality for flexible operations:** Flexible operations require consistent fuel quality, particularly during frequent ramping to balance renewable generation. Variations in coal quality can increase the risk of thermal stress, equipment fatigue, and unit tripping. Regulators ought to require systematic inventorying and transparent disclosure of fuel quality, on a monthly to weekly basis, by generators and fuel suppliers. Integrating such disclosures within Fuel Supply Agreements and regulatory reporting frameworks will strengthen accountability, improve operational planning, and ensure reliable plant performance under increasingly flexible operating regimes.

XI. **Ensure compliance with latest air emission standards under flexible operations:** Flexible operations may lead to increased coal consumption and higher emissions of air pollutants due to frequent ramping, start–stop cycles, and part-load inefficiencies. Units must therefore comply with the latest notified emission standards under all operating conditions, including low-load and cycling regimes. In addition, clear operational guidelines and standard operating procedures (SOPs) should be established to manage emissions during flexible operations, supported by robust monitoring and reporting frameworks. This is critical to ensure that flexibilisation does not create unintended public health risks or undermine environmental regulatory objectives.

XII. **Reform PPA structures to mitigate litigation risks**: Current PPA structures are largely availability-based, with assured payments based on plant availability (typically around 85 per cent), regardless of actual dispatch. This model is misaligned with the evolving role of thermal plants under flexibilisation, where utilisation is expected to decline. Additionally, existing PPAs embed return expectations for lenders and investors based on higher plant load factors, creating financial risks if dispatch reduces. On the fuel side, FSAs often require fixed coal offtake commitments, which may become redundant under lower utilisation scenarios. These structural mismatches between PPAs, FSAs, and the operational reality of flexible thermal generation can lead to contractual disputes and litigation. A coordinated reform of these frameworks is therefore necessary to align incentives, reduce financial risks, and ensure smooth implementation of flexibilisation without future legal bottlenecks.

Recommendations for State Regulators

I. **States need to issue flexibility related tariff policy**: State ERCs ought to undertake tariff regulations for flexible operations to bring state and private units under their jurisdictions under compliance obligation. Currently, only five state ERCs have issued these tariff regulations. The CEA's phasing plan includes 15 states, thus showcasing that 10 states are yet to implement policies for flexible operations. Non-issuance disincentivises uptake and unreasonably burdens the complying units by necessitating lower generation for their units during dispatch schedules.

II. **Driving Flexibility through State Power Utilities**: State Power Corporations and DISCOMs should prioritise flexibilisation of state-owned coal-based thermal power plants through revised operational protocols, retrofit investments, and incentive-linked scheduling mechanisms. Since these utilities directly own and operate a significant share of India's thermal fleet, faster adoption of flexible operations at the state level can substantially accelerate RE integration.

III. **Enhance demand forecasting**: Electricity demand forecasting methodologies ought to be updated with a shift towards 4x4 km mapping, industrial and residential consumption mapping, and upscaling local weather forecasting capabilities. The closer the demand forecasting prediction is, the lower will be the ramping fluctuation for generation unit, reducing the impact of flexible operations on unit's life and equipment. Accurate and robust demand estimates are critical for informed coal fuel and generation planning. Spain's recent unexpected clouding event, which sharply reduced solar generation and contributed to a blackout, underscores the critical need for more robust demand and generation forecasting systems that can anticipate and manage short-term variability in renewable output. Additionally, this reduces the scale of RE curtailment as RE generation can be more accurately predicted.

Recommendations for Power Generators

I. **Undertake retrofit and operational readiness assessment:** The foundation of flexibilisation lies in unit-level assessment of both technical retrofit requirements and operational readiness. Generating utilities should undertake structured engineering evaluations to identify control system upgrades, equipment reinforcement needs, and operational envelope adjustments required for sustained low-load and ramping performance. The assessments should cover the following:
   - ***Technical retrofits***: Upgradation of plant systems to achieve lower minimum technical load, deployment of advanced control and automation systems, and identification of equipment modifications required to support frequent cycling and ramping.
   - ***Operational measures***: Strengthening maintenance practices, improving fuel quality management to ensure stable combustion at low loads, and enhancing operational protocols for flexible operation.
   - ***System integration***: Preparing units for participation in ancillary service markets and real-time grid support mechanisms.

Early identification of these requirements enables realistic cost estimation, reduces execution uncertainty, and supports timely engagement with OEMs, suppliers, and regulators. The studies should catalogue plant-specific modification pathways, prioritise interventions, and align implementation sequencing with the national phasing framework.

II. **Upskill workforce programme:** Flexible operation places new operational demands on plant personnel, requiring continuous monitoring of ramp behaviour, transient equipment stress, and interaction with automated dispatch signals. Existing staffing structures and training regimes remain largely oriented toward baseload operation, creating capability gaps that can affect reliability and equipment health. Power generating companies should therefore establish structured training and transition programmes focused on ramp management, transient monitoring, and digital control interaction. Building operator capability will reduce operational risk, strengthen equipment protection, and improve confidence in sustained flexible operation.

III. **Enable OEM provider engagement:** Information asymmetries regarding equipment modification pathways, performance limits, and operational adjustments often slow adoption. The effectiveness of plant-level flexibility deployment is contingent on transparent information sharing regarding equipment health and overall performance, while consistent tracking and data recording will aid faster integration of new systems for flexible operations. Unit management ought to train plant personnel to ensure a coordinated effort with OEM providers for deployment efficiency.

To read the full policy on "Flex to Fix: Deciphering India's Coal Flexibilisation Challenge for RE integration" scan the QR code given below -

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India's non-fossil based installed capacity has surpassed fossil-based capacity, fundamentally reshaping the power grid. Over the past decade, the share of solar energy has increased 3.5-fold to reach 140 GW, and with 100+ GW under construction, the daily power generation mix is now permanently altered. Coal-based thermal energy operations are shifting from consistent baseload to a more adaptable role, accommodating RE generation, especially during daytime. The unified national GRID requires flexibility from its largest energy resource.

To equip the fleet to operate flexibly, the Government of India notified the *Central Electricity Authority (Flexible Operation of Coal-based Thermal Power Generating Units) Regulations, 2022* on January 25, 2023. The phasing plan aims to transition India's coal fleet to a minimum technical load of 40 per cent while enhancing each unit's ramping ability above one per cent per minute.

This report examines India's progress in implementing coal flexibilisation while evaluating the technical, economic, regulatory, and institutional barriers shaping the transition. It assesses the costs of integrating flexible operations via retrofits and draws lessons from international experience in China, Chile, and Germany. Through system-level appraisal and policy analysis, the report highlights the decarbonisation potential embedded in accelerating its execution. Built with inputs from sector experts, the research aims to strengthen regulatory and tariff frameworks, empowering coal-based thermal power to support higher RE integration while maintaining grid reliability and affordability.

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