CENTRAL ELECTRICITY REGULATORY COMMISSION
(NEW DELHI)

Explanatory Memorandum for the "Draft Central Electricity Regulatory Commission (Terms and Conditions of Tariff) (Second Amendment) Regulations, 2025.

1. Background

1.1 The Central Electricity Regulatory Commission ("the Commission"), exercising powers under sub-clause (s) of clause (2) of Section 178 of the Electricity Act, 2003 ("the Act") read with Section 61 and Section 62 of the Act, has notified the Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2024 (hereinafter referred to as the "Principal Regulations" or "Tariff Regulations, 2024"). These regulations provide the terms and conditions for tariffs applicable to the Central generating stations, other generating stations with a composite scheme, and the inter-State transmission system, where the Commission determines the tariff under Section 62 of the Act. The Draft Central Electricity Regulatory Commission (Terms and Conditions of Tariff) (Second Amendment) Regulations, 2025, were issued on 1st December 2025, inviting comments/ suggestions/ objections from the stakeholders.

1.2 Integration of large-scale variable energy resources necessitates additional measures for grid stability and reliability of the power system to minimise operational risk of the grid, and enable the infusion of other flexible generation resources into the grid to balance the variability of the renewable generation. As on 31st December 2025, India has achieved non-fossil fuel share of 266.78 GW (renewable energy, hydro and nuclear) within a total grid capacity of 513.72 GW, domestic solar module manufacturing capacity increased to 144 GW from 5.4 GW in 2014 and PV cell capacity around 25 GW in FY 2025 from 1.2 GW in 2014.

On the need for flexibility of the generating station -

1.3 At present, the system operation largely depends on conventional generating stations to meet the base load requirement and to balance the large-scale variable solar and wind generation in the power system. The available capacity of Gas-based thermal power generation and pumped storage hydro generation are inadequate to provide support for reserves. This is because of the high cost of gas generation and the developmental challenges in establishing Pumped Storage Plant (PSP) capacity. Globally, countries have adopted certain generation resources as transition fuels or generation resources are selected when adopting the energy transition strategies. For example, European countries have adopted gas-based generating resources to balance VRE, whereas Brazil has used its abundant Hydro resources. In India, coal-based generation has become the unanimous choice as a transition fuel for the clean energy transition despite its technical limitations, such as quick ramp-up and long start-up time. Thus, if the coal-based generation resources are to be used as a transition fuel in India, there is a need to enhance the flexibilisation capabilities of coal-based generating stations to absorb the variability and intermittency of renewable generation in India.

1.4 Coal-based thermal generation faces a limitation in bringing down the generation below the technical minimum level. If a thermal generating unit is taken out during the period of high availability of renewable energy in solar hours, there will be a power shortage in the evening peak hours. Therefore, there is a critical need for enhancing the flexibility of the fleet of conventional generation resources in India to enable them to operate at lower than technical minimum levels and to meet the requirements of frequent changes in schedules of generation output through ramp-up and ramp-down modes.

On the need for reliability of the power system-

1.5 Absence of adequate flexible resources has serious consequences on the reliable and secure operation of the power system and may cause impediments in integrating renewable energy. Section 28 of the Act lays down the obligations of the Regional Load Despatch Centres for carrying out real-time operations for grid control and the dispatch of electricity, and for the secure and economic operation of the regional grid in accordance with the Grid Code specified by the Commission. Hence, the security of the grid is to be enforced by the Regional Load Despatch Centres as per

the regulatory framework specified by the Commission under the Grid Code. The National Load Despatch Centre has reported several incidents of high-frequency operation and consequent curtailment of renewable generation.

1.6 Apart from the above, there is a need to strengthen and streamline existing regulatory frameworks. The existing borrowing practice needs to be made more efficient by introducing an obligation to restructure some loans with interest rates higher than the reference rate. The existing framework for allowing Ash Transportation Expenses to be addressed separately at the end of the true-up period is to be streamlined to prevent heavy carrying costs on the beneficiaries. The Overburden adjustment and GCV adjustment formula provided in the existing regulation may cause difficulties for the generating company or mining company, where Mine, Developer and Operator contracts are executed prior to the notification of the regulatory framework, also needs to be addressed. A regulatory sandbox framework is to be established to encourage research and pilot projects in the power sector. Some of the existing regulatory frameworks have been further streamlined, as discussed in the subsequent sections.

Proposed amendments

1.7 In this backdrop, the Commission has proposed certain amendments in the Principal Regulations to introduce the following:

- regulatory framework for integration of the integrated energy storage systems with the generating stations and the inter-state transmission system,
- streamlining the framework for the determination of the input price of integrated mines,
- amendments in the regulatory framework for the determination of tariff of inter-state transmission system,
- amendments relating to O&M expenses of Generating Stations and Inter-state transmission system (ISTS), and
- introduction of the provision for recovery of expenditure incurred for Regulatory Sandboxing.

1.8 The integration of an energy storage system with the generating station will enhance the flexibility of thermal generating stations for following the demand profile, pave the way to increase the absorption of the generation from variable sources and improve the efficiency by increasing PLF of the generating stations. The integration of an energy storage system with the transmission system will enhance the grid stability and reliability of the power system by quickly responding to fluctuations in demand and supply through an integrated energy storage system. The proposed regulatory framework is technology agnostic and includes all types of energy storage systems, which can be integrated with generating stations and transmission systems. At present, battery energy storage systems are feasible solutions, and hence, we have discussed the characteristics of the battery energy storage system.

2. Overview of the proposed amendments

Integrated Energy Storage System

2.1 The proposed introduction of a regulatory framework is for the integration of Energy storage systems with the thermal generating stations or the interstate transmission system. The regulatory framework for the integrated energy storage system comprises the following:-

a) Determination of storage tariff for the integrated energy storage system installed at a coal-based thermal generating station or the interstate transmission system, as the case may be;

b) Scheduling and Dispatch mechanism for the integrated energy storage system operated with the coal-based thermal generating station or interstate transmission system, as the case may be; and

c) Mechanism for utilisation of stored electricity in an integrated energy storage system through the open market or ancillary market.

2.2 Brief overview of the amendments proposed in the Tariff Regulations, 2024, for the integrated energy storage system is as under:-

i) Clauses related to applicability of the regulations related to integrated energy storage system. *[Regulation 2(a), 3 (24), 3 (82), 3 (87)(j)]*

ii) Additional definitions pertinent to the integrated energy storage system. *[Regulation 3A]*

iii) Date of commercial operation of the integrated energy storage system. *[Regulation 5(3)]*

iv) Inclusion of an integrated energy storage system in tariff determination. *[Regulation 8, 9 (3a), 9(4a), 10(1), 10(1) Explanation]*

v) Inclusion of in-principle approval for the integrated energy storage system. *[Regulation 11(1) and 11(2)]*

vi) Provision in the existing truing-up mechanism, and supplementary tariff, for an integrated energy storage system. *[Regulation 13 and 14]*

vii) Supplementary storage charges of the integrated energy storage system. In the existing provisions for capacity charges and energy charges. *[Regulation 15 and 16]*

viii) Inclusion of an integrated energy storage system in the existing provision for Debt-Equity Ratio. *[Regulation 18]*

ix) Inclusion of an integrated energy storage system in the existing provision for initial spares. *[Regulation 23]*

x) Enabling provision in existing clauses of additional capitalisation and introductions of new Regulations 29A and 29B relating to additional capitalisation for Integrated Energy Storage Systems (IESS). *[Regulation 24, 25, 26 and Regulation 29A and 29B]*

xi) Introduction of a regulatory framework for calculation of return on equity, depreciation, interest on working capital, interest in loan and Operation & Maintenance expenses in case of an integrated energy storage system installed with the generating station or the transmission system. *[Regulation 30(4), 32, 33 (13), 34(1)(e) & 36(4)]*

xii) Regulatory framework for computation of supplementary capacity charges, supplementary energy charges on account of the integrated energy storage system. [Regulation 57, Regulation 61A, Regulation 64A, and 64B]

xiii) Introduction of norms of operation of the integrated energy storage system. *[Regulation 70 (FF)]*

xiv) Enabling clause introduced for methodology of scheduling and dispatch for the integrated energy storage system, along with the generating station, shall be as specified in the Grid Code. *[Regulation 74]*

xv) The framework for consideration of storage charges as part of the transmission charges, in relation to the integrated energy storage system, introduced a new provision for the sharing of gains on account of storage services. *[Regulation 78 & 84A]*

Bringing efficiency and discipline to borrowing loans

2.3 A new proviso proposed to bring efficiency in borrowing of the loans for the generation and transmission projects. *[Regulation 32 (5)]*

Streamlining the O&M Expenses

2.4 Streamlining the regulatory framework of the O&M expenses towards ash transportation expenses, new hydro generating stations and specific transmission systems:

i) Ash Transportation Expenses allowed to be settled on a monthly basis to avoid interest burden on the beneficiaries. *[Regulation No. 36(1)(6)]*

ii) Review of norms of O&M Expenses for HEP to be commissioned during the control period of 2024-29; and *[Regulation No. 36(2)(a)]*

iii) Introduction of Specific norms for O&M Expenses for the specific transmission system developed by the Bhakra Beas Management Board. *[Regulation No. 36(3)(a)]*

Strengthening the framework of the Input Price of the integrated mine

2.5 Review and strengthening of the regulatory framework of the Input price of coal and lignite for energy charges as under:-

i) Introduced the clause for allowing an interim input price up to 90% of the claimed input price after the first hearing of the application. [*Regulation No. 37(3)]*

ii) Allocation of mine under the Mines and Minerals (Development and Regulation) Act, 1957 or any other applicable Act, is recognised alongside the existing Coal Mines (Special Provisions) Act, 2015, to cover mines that are still covered under the older enactment. *[Regulation 39(1) and (2), 53(1)]*

iii) Clarification that no incentive for the production of coal up to 100% of the annual target quantity and sharing of savings for exceeding production beyond 100% of the annual target quantity. [*Regulation No. 39(1), 39(2) and 39 (4A)]*

iv) Scope of capital cost expanded to include the pre-investment approval expenditure and streamlining the treatment of IDC & IEDC in case of an integrated mine. [*Regulation No. 42(1)(a)]*

v) The scope of additional capital expenditure in case of an integrated mine is expanded to include the expenditure with the Board approval in addition to the mine plan. [*Regulation No. 42(1)(a) and 42(2)(a)]*

vi) Streamlining the treatment of a conditional freehold land is treated at par with leasehold land for the purpose of amortisation, treatment of realisable value after operational life or alternate use in case of an integrated mine. *[Regulation 45(2) proviso(ii)]*

vii) The scope of the comparison of the input price is expanded to include the use of alternative coal in addition to the commensurate grade of coal of Coal India Limited, and addressing the situation of a low-demand scenario in the case of the input price of lignite mine. [*Regulation No. 50(2) & 50(3)]*

viii) Overburden adjustment and GCV adjustment formulae agreed by the generating company are recognised to prevent the complexity in the event of a difference, allowing the generating company to evolve the suitable OB

adjustment and GCV adjustment treatment while maintaining the regulatory oversight. *[Regulation No. 51(3)(a), 51(3)(b)(iii), 51(3)(b)(vi) and 52(2)(b)]*

Framework for Regulatory Sandbox

2.6 Introduction of a regulatory framework for participation in the regulatory sandbox on a participation fee basis. [New Regulation 101A]

Additional Amendments

2.7 Some of the additional amendments have been proposed as under:-

i) Streamlining methodology for calculation of availability of the transmission system by considering separate elements of Thyristor Controlled Series Reactors (TCSCs) or Fixed Series Reactors. [Appendix-IV & V]

ii) In line with the above proposed amendments, the corresponding amendments to the Tariff Filing Forms and a few editorial changes as proposed in the draft notification. *[Annexure-I]*

iii) Additional capitalisation on account of Renovation and Modernisation to the transmission system has been dispensed with in the Principle regulation, and its applicability is limited to the generating stations. *[Regulation 27]*

iv) A new clause was added to enable the National Load Despatch Centre to frame suitable guidelines for measurement of ramp rate of the generating unit by considering the energy measurement at a suitable interval. *[Regulation 30(3)]*

v) True up petition application to be filed by the generating company at the end of the tariff period for pass-through of additional cost due to shortfall in energy charges of the Hydro generating station. [Regulations 65(7)]

3. Enablers for the Energy Storage System in the Power Sector

Policy and Regulatory Measures

3.1 The Central Government has recognised the energy storage system in the National Framework for Promoting Energy Storage Systems, introducing several policy measures and incentives, including the following measures:-

i) On 11th March, 2022, the Central Government, u/s 63 of the Act, issued Guidelines for the procurement and utilisation of battery energy storage systems as part of generation, transmission and distribution assets along with Ancillary services. It provides for the procurement of energy from battery energy storage systems through competitive bidding from grid-connected Projects to be set up on a "Build-Own-Operate" or "Build-Own-Operate-Transfer" basis.

ii) On 29th December, 2022, the Central Government notified the (Electricity Amendment) Rules, 2022 that provide the Energy Storage Systems to be considered as a part of the power system, as defined under section 2(50) of the Act which can be used either independently or as a network asset or in conjunction with generation, transmission, and distribution infrastructure and would be accorded same legal status as that of the owner based on its application area i.e., generation, transmission, and distribution.

iii) On 22nd July 2022, a long-term trajectory for Energy Storage Obligations (ESO) was notified by the Ministry of Power and on 23rd November 2021, the waiver of inter-state transmission charges for energy storage system was issued.

iv) The Union Cabinet has also approved a Viability Gap Funding scheme to develop 4,000 MWh of BESS projects by 2030–31 in the initial phase with budgetary support of up to 40% of capital cost, which was subsequently scaled up to 13,200 MWh.

v) On 31st Jan 2022, the CERC (Ancillary Services) Regulations 2022, notified to provide eligibility of ESS to provide Secondary Reserve Ancillary Service (SRAS) and Tertiary Reserve Ancillary Service (TRAS), under certain conditions. If the BESS is integrated with the existing thermal power stations, the generating company can provide ancillary services as per the requirements of the system operator.

vi) On 9th June, 2025, the Central Government announced another Viability Gap Funding scheme for the development of a Battery Energy Storage System of

30,000 MWh capacity, wherein the funding is offered for the Section 62 Generation projects also.

Economic & Technical Enablers

Primary frequency reserve source

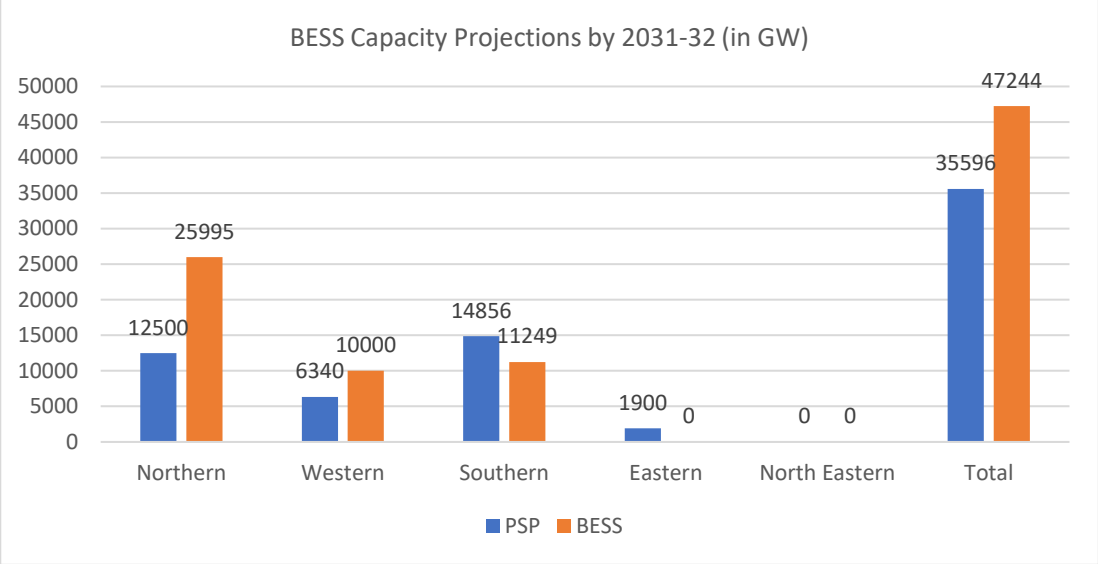
3.2 The technical characteristics of the battery energy storage system are suitable for frequency reserve resources over other conventional sources.

Diverse uses of the storage system in the Power system

3.3 The energy storage system can absorb surplus power of the generating station during low net demand hours and discharge during high demand peak hours, providing services such as peak-shaving, frequency regulation, ramping support and congestion relief, thereby enhancing reliability of the Power system.

Capacity Projections in the National Electricity Plan

3.4 The National Electricity Plan 2032, issued by the Central Government, under Section 3 of the Electricity Act, 2003, identifies storage as a core pillar of system planning. Complementary guidelines have also been issued by the Central Government to promote integration of energy storage systems with renewable and hybrid tenders alongside pumped storage projects, signalling an intent to mainstream storage in future capacity additions. India's capacity projections for Energy Storage Systems highlight the centrality of flexible and storage assets in achieving high renewable penetration while maintaining system stability and security.



[1]

Figure : India's energy storage capacity projections (Source – CEA)

3.5 The regulatory framework for the integrated energy storage system covers the various aspects of the infrastructure cost as part of capital cost, framework for the tariff structure and determination of tariff, mechanism for recovery, scheduling and dispatch mechanism and mechanism for utilising stored electricity in the energy storage system through the open market or ancillary market.

4. Proposal I: Enhancing the grid stability and reliability of the power system by quickly responding to fluctuations in demand and supply through an integrated energy storage system in the interstate transmission system

4.1 The change in generation mix due to the addition of variable generation resources gives rise to challenge to the grid stability and reliability of the power system. The operational risk of the grid has increased due to variable generation, forecasting errors, and inadequate reactive power support.

Issues

[1] Revised on 27th January, 2026 as per NEP

High frequency during Solar-Hours (6:00-18:00 hrs)

4.2 The operational risk of the grid increased as it operated at high frequency due to overgeneration or low frequency due to high demand. The generation from Solar projects is injected into the grid during solar hours. The grid experiences surplus generation and inadequate down reserves, leading to high frequency during solar hours, as depicted below

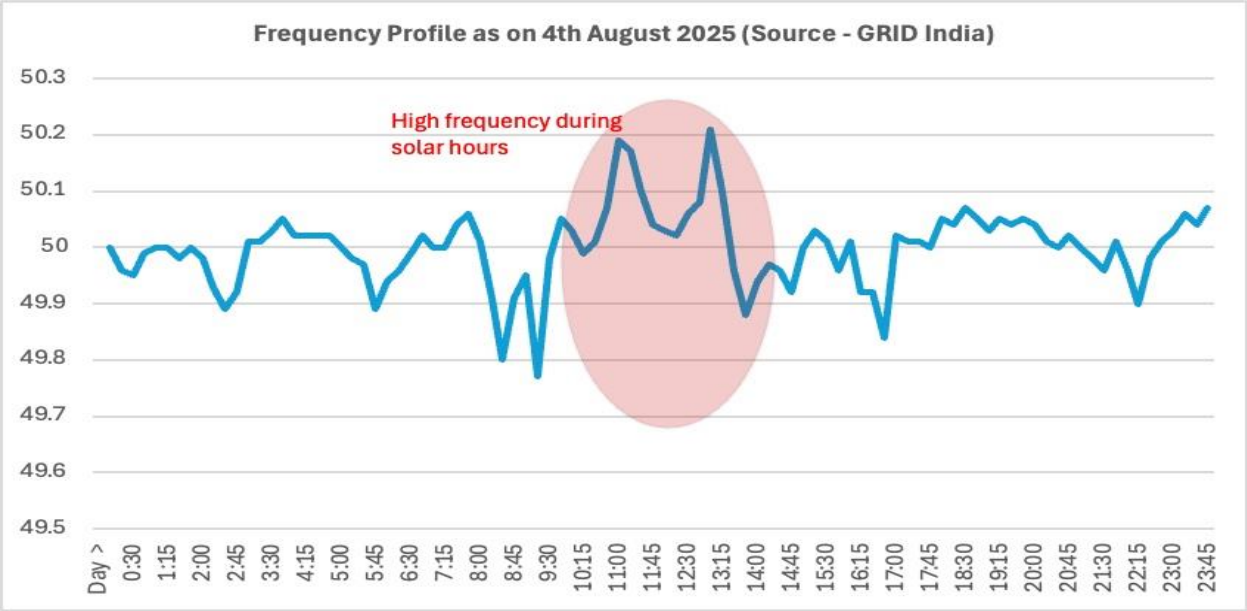


Figure : Grid operation challenges due to increasing RE (Source - Grid India)

Low frequency during Non-Solar-Hours (18:00 to 6:00 hrs)

4.3 During non-Solar hours, in the evening peak, i.e. 18:00 - 21:00 hours, the solar generation is not available. At the same time, the generating units that were forced to shut down during the day to accommodate solar generation cannot be brought back into operation. Hence, the grid faces a constraint due to a shortage of up reserves that can ramp up the generation quickly, leading to overloading of the power system, reflected in the low frequency. The power system still frequently exhibits insufficient reserve margins, which may force the resort to load-curtailment to prevent the grid disturbances as depicted in the graph below:

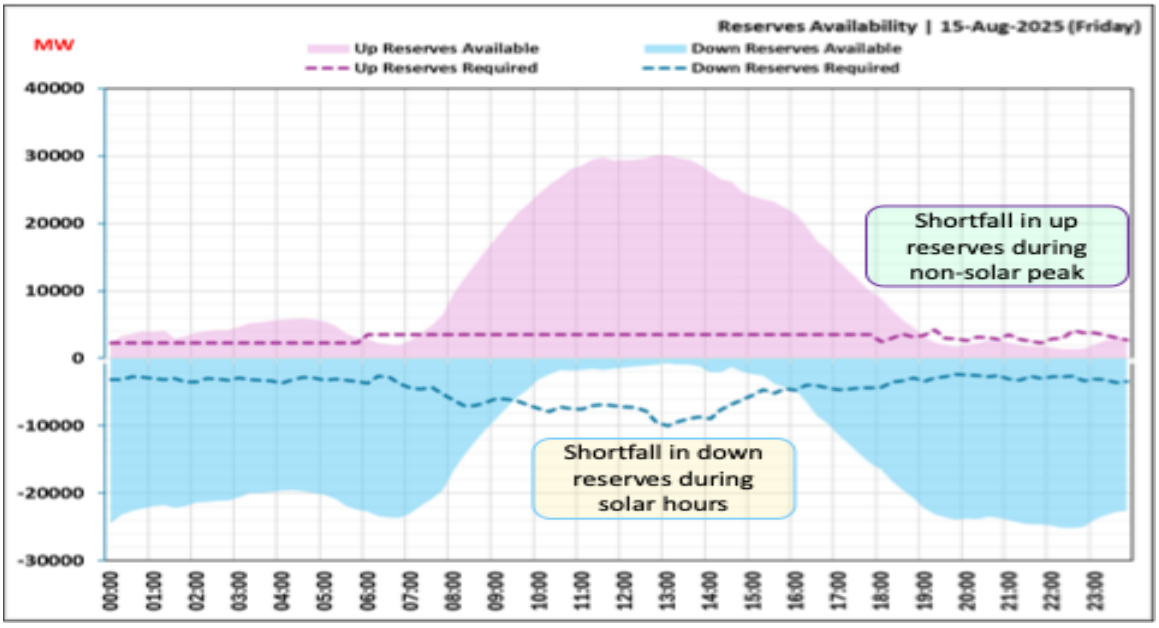


Figure: Reserve adequacy challenges due to high solar penetration

Inadequate frequency response resources for ensuring reliability

4.4 The variation of the Solar & wind generation depends on weather conditions, causing unpredictable output variations. The National Load Despatch Centre also reported that the cloud cover incident occurred in Rajasthan, where approximately 10-12 GW of renewable generation dropped suddenly, which can be seen from the following graph of real-time system frequency. The sudden drop in renewable generation due to weather vulnerability and the variation in the generation calls for the reserves to contain the frequency excursions.

4.5 The requirement of reserves can be made available through: (i) mandatory participation for large generators; (ii) symmetric reserves (must provide both upward/ downward regulation); (iii) market-based reserves, and (iv) battery/Pump storage & demand response. The Grid Code mandates coal and hydro generating stations to operate in governor mode and to use market-based Reserve Ancillary Service (RAS), which includes other resources such as energy storage systems.

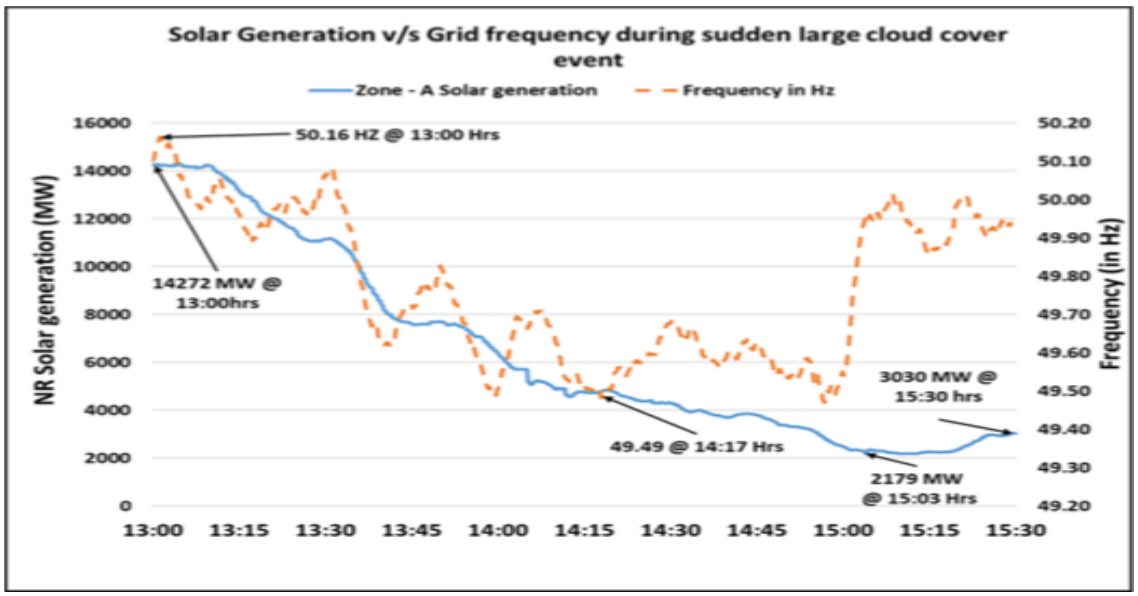


Figure : Grid frequency challenges owing to sudden drops in RE generation

4.6 For ensuring frequency control, the Grid Code envisages the use of an Energy Storage System for Primary control under Regulations 30(10)(a) and (e), for Secondary control under Regulation 30(11)(b) and (v) and for Tertiary Control under Regulation 30(12)(i) of the Grid Code.

4.7 In order to ensure the availability of reserves as explained above for managing the frequency or for any other purpose, the Energy Storage System can also be deployed in the Substation of the Transmission system as a transmission element.

4.8 Moreover, at the state level, with the solarisation of feeders under the PM KUSUM scheme, any excess RE power in these feeders can be utilised for charging ESS at the Substation level itself. Hence, energy storage systems can store this excess power in the system quickly and thereby support the grid whenever required.

4.9 In Australia[2], Germany[3] and California[4], the Battery Energy Storage systems are used to provide the primary frequency response for frequency control. Hornsdale Power Reserve in South Australia, a 100 MW/ 129 MWh Battery, is directly connected to the National Electricity Market (NEM) transmission system via the Hornsdale wind farm's substation to provide grid support, stability, and frequency control, demonstrating the viability of large-scale batteries in Australia.

4.10 Legal framework prescribed under Rule 18 of the (Electricity Amendment) Rules, 2022 provides that the energy storage system can be developed co-located with a transmission system and utilised in a complementary manner with the transmission.

Proposal

4.11 It is proposed that a dedicated energy storage system may be established by the transmission licensee, integrated with the existing sub-station or developed with the new sub-station of the interstate transmission system. The objective of an integrated energy storage system with the transmission system is to enhance grid stability, and be treated as a transmission element.

Uses of the integrated energy storage system with the transmission system

4.12 The primary use of the dedicated energy storage system integrated into the transmission system will be to ensure the grid stability and reliability. This can be achieved by using ESS for (a) balancing the intermittency of renewable energy sources, (b) regulate frequency, (c) shift peak power, and (d) to relieve the congestion according to the usage priorities as may be specified by the Commission.

Charging of the integrated energy storage system

[2] In Australia, Hornsdale Power Reserve of 100 MW/129 MWh Battery Energy Storage System of Tesla reduced frequency control costs by 90% and improved grid reliability in South Australia during high wind penetration.

[3] In Germany, the Battery Energy Storage System provides fast frequency response to compensate variable generation from wind power.

[4] In California, the battery energy storage system facilitates to manage the duck curve by storing excess solar energy and discharging it in the evening.

4.13 The procedure for charging, scheduling and dispatch of electricity, and energy accounting for the integrated energy storage system with the transmission system shall be prepared by National Load Despatch Centre in consultation with the Regional Load Despatch Centre & Regional Power Committee, consistent with the Grid Code, to be issued after stakeholders' consultation.

Location of the integrated energy storage system with the transmission system

4.14 The integrated energy storage system with the transmission system will be installed at a strategic location identified by the Central Transmission Utility in consultation with the system operator and transmission licensee.

Tariff of the integrated energy storage system with the transmission system

4.15 The tariff of the integrated system operator shall be determined by the Commission separately by treating infrastructure cost as additional capital expenditure. The two-part supplementary tariff structure will be applied to the integrated energy storage system.

Role of the transmission licensee in the operation of an integrated energy storage system with the transmission system

4.16 The role of the transmission licensee in the operation of the integrated energy storage system will be to provide storage services without taking ownership of the energy, and the income generated from it will be ploughed back to reduce the yearly transmission charges. Except for the scheduling of energy storage for the system operator's grid reliability, all other transactions will be on a commercial principle basis.

Proposed amendments

4.17 Accordingly, amendments have been proposed in Regulations 2(a), 3 (24), 3 (82), 3 (87)(j), 3A, 5(3) and 74 of the Tariff Regulations, 2024.

5. *Proposal II: Enhancing the flexibility of thermal generating stations through an integrated energy storage system;*

Issues

5.1 The scale of renewable energy transition depends on the availability of transition fuel or balancing generation resources, which play a crucial role in clean energy transition and renewable energy integration. In the USA and European countries, gas is used as a balancing generation resource, whereas in Brazil, Hydro is used as a balancing generation resource. In India and China, coal is used as a balancing fuel. However, in China, indigenous storage manufacturing capacity enabled it to integrate more renewable generation. The share of generation from various sources for major economies along with transition fuel, is given below:-

Countries	**Renewables** (excluding Nuclear)	**Fossil Fuels** (coal, gas, oil)	**Nuclear**	**Transition fuel**
European Union	45–48%	27%	23%	Gas
USA	23%	59%	18%	Storage
China	34%	60%	5-6%	Coal + Storage
India	20-21%	74.5%	3%	Coal

5.2 The situation of overgeneration exists despite the thermal generation being operated at the minimum turndown level during peak solar hours, which increases high-frequency operations vulnerable to the grid security, as depicted in the following graph.

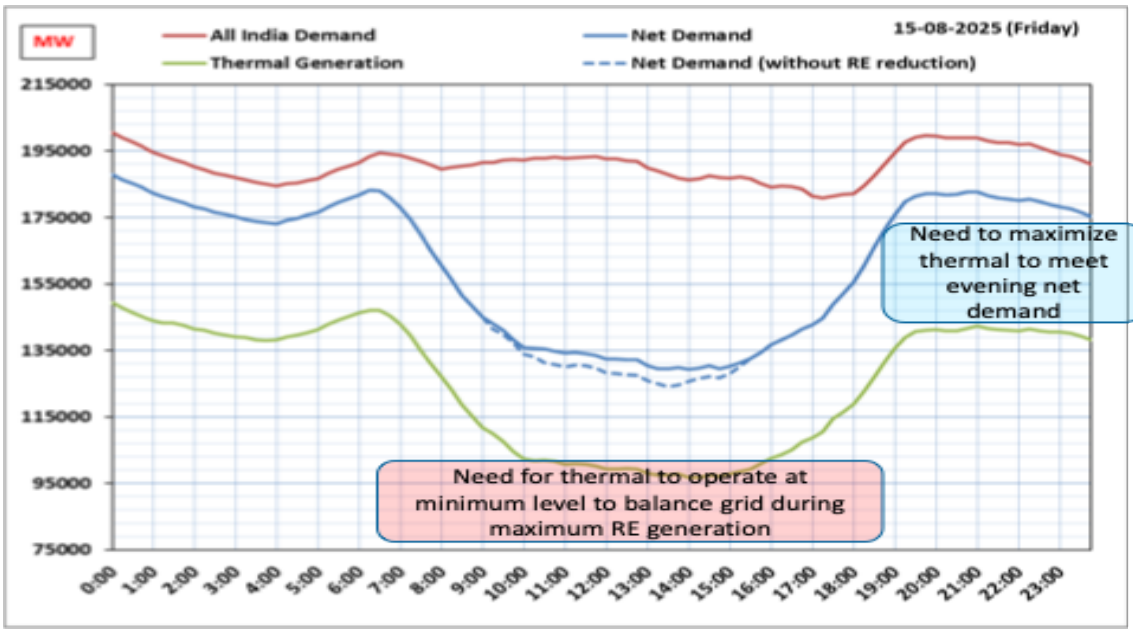


Figure : Grid operation challenges due to increasing RE (Source - Grid India)

In India, Gas-based thermal power generation is unable to provide adequate, flexible generation due to the problem of the non-availability of domestic gas and the high cost of imported gas. Hence, making the coal-based thermal generation fleet more flexible is the only available option to absorb the increasing variable renewable generation in India.

5.3 Coal-based thermal generation is considered a predictable and firm resource. The table below compares Coal, Gas, and Hydro-based generation with respect to the following parameters: Predictability, Variability, and Flexibility.

Type of Generation Resource	Predictability	Variability	Flexibility
Thermal (Coal/Lignite)	High	Low	Slow
Thermal (Gas)	High	Low	Fast
Hydro (Reservoir)	High	Low	Very fast

5.4 The characteristics of the Coal-based thermal generation may not offer adequate flexibility required to meet the integration of a large quantum of Renewable Energy into the Grid.

5.5 In a 24-hour cycle, a coal-based plant generally gets dispatch schedule less than the technical minimum during daytime, in view of high Solar power availability during daytime. For the remaining part of the day, it gets a reasonable schedule, the schedule is maximum during evening peak hours. It has to over-injected into the grid during daytime to be able to run at minimum turndown level, so that it is on bar to meet the evening peak-hour demand of the beneficiaries. Over-injection into the grid to prevent a shutdown may attract a penalty under the Commission's deviation settlement mechanism. However, if the generating company resorts to shutting down the generating plant in view of low schedule during daytime, the beneficiaries will be deprived of electricity supply during evening peak hours.

5.6 One possible solution is to deploy the integrated energy storage system co-located with the generating station. The surplus generation from the thermal generating unit, above the schedule, can be used for charging the integrated energy storage system. This will give the necessary flexibility to the generating plant to be on bar, even when the schedule is less than minimum turndown level, so that the requirements of the distribution companies are met for the evening peak.

5.7 Sub-rule (2), (3), (4) and (5) of Rule 18 of the (Electricity Amendment) Rules, 2022 provides that the energy storage system can be developed co-located with a generating station or the transmission system and utilised in a complementary manner with generation, transmission and distribution.

5.8 It is proposed that an integrated energy storage system integrated with the existing or new generating station may be developed by the generating company within the scope of the generating station.

Uses of the integrated energy storage system with the generation assets

5.9 The energy storage system will be used for the purpose of enhancing the flexible operation of the generating unit and shifting of energy output in line with

the requirements of the beneficiaries of that generating station, as per the supplementary storage cost determined by the Commission. The energy storage systems integrated with the generating station will also be used to improve flexibility, balance the intermittency of renewables, increase the PLF of the generating stations, and support frequency regulation as decided by the Commission.

Charging of the integrated energy storage system with the generating station

5.10 The energy storage system integrated with the thermal generating station can store surplus thermal energy during periods when the available schedule from beneficiaries is lower than the declared capacity and deliver it during periods of high demand during the day. The beneficiaries can also get to store surplus generation above the technical minimum level, in accordance with their demand requirements. Apart from this, the beneficiaries have the liberty to store the surplus generation from any other generating station, including the renewable generation. The multi-use of the energy storage system enables the generating station to utilise its assets optimally and to ensure two-cycle operation.

Location of the integrated energy storage system with the generating station

5.11 The integrated energy storage system can be installed at any thermal generating station. The selection of thermal station shall depend on various factors such as the likely schedule that the station receives, the Energy Charge Rate (ECR), availability of transmission margins at the switchyard etc.

Tariff of the integrated energy storage system with the generating station

5.12 The tariff of the integrated energy storage system with the generating station shall be determined by the Commission separately, treating infrastructure cost as additional capital expenditure. The two-part supplementary tariff structure will apply to the integrated energy storage system, enabling flexible use by the generating station. It will prevent sudden tariff increase due to depreciation loading, when the balance life of the generating station is shorter. The two-part supplementary tariff structure will ensure greater transparency in the cost of the assets.

Scheduling of the stored energy in the integrated energy storage system with the generating station

5.13 The scheduling of energy stored in the integrated energy storage system with the generating station will be carried out in the same manner as the scheduling of generation from the generating station. Scheduling by the beneficiary or the generating company from external generation sources will be carried out on a bilateral basis. The ownership of the energy stored in the integrated energy storage system lies with the generating company or the beneficiaries, depending on the use and charging source.

Role of the generating company in the operation of an integrated energy storage system with the generating station

5.14 The manner of the role of the generating station in the operation of the integrated energy storage system will be the same as that of the generation assets. If the generating station provides storage services to its own beneficiaries, the ownership of such energy lies with those beneficiaries. If the generating company provides storage services to a third party or for ancillary services, the income generated from such services will be ploughed back to reduce the tariff for the energy storage system. Except for scheduling energy storage for grid reliability by the system operator or for providing storage services to their own beneficiaries, all other transactions will be on a commercial basis.

Proposal

5.15 Accordingly, amendments have been proposed in Regulations 2(a), 3(24), 3(82), 3 (87)(j),3A, and 5(3) of the Tariff Regulations, 2024.

---

6. *Proposal III: Determination of storage tariff for the integrated energy storage system installed at a coal-based thermal generating station or the interstate transmission system, as the case may be.*

Issue

6.1 The energy storage system integrated with the existing generating station or the interstate transmission system is of a complementary nature, as it would become part of the project, providing the energy services to the same beneficiaries within the

existing commercial arrangement and the manner of recovery of storage charges thereof. It is an accepted fact that storage services can add value to the electricity generated from a generating station or transmitted through the transmission system, as the case may be. However, storage system services can be multi-use, and the storage system's life may not coincide with the generation or transmission project. Thus, merging capital costs and tariffs within existing transmission or generation assets may make tariff determination difficult and limit flexibility, leading to suboptimal utilisation of storage assets.

Analysis

6.2 The CERC (Terms and Conditions of Tariff) Regulations, 2024, provide the regulatory framework for the determination of tariffs for generating stations, inter-state transmission systems, supplementary tariff of emission control systems, and the input price of coal or lignite from the integrated mine. The Commission has recognised the dedicated use of the mine allocated to the particular generating station as an integral part of the generation project and specified the framework for the input price of coal separately, considering the multi-use for more than one generating station. Further, for the revenue stream of the emission control system, the assets have been considered part of the generation project, as they are co-located with it. Similarly, the revenue stream from the integrated energy storage system integrated with the generating station can also be considered separately.

6.3 The CERC (Terms and Conditions of Tariff) Regulations, 2024, recognise the compensation devices, such as the Static Compensation System, as a separate element, as it provides the complementary service of reactive compensation to the transmission system. Similarly, an integrated energy storage system with the transmission system can also provide reliability services or congestion management, alongside other uses of storage services.

6.4 In the case of the energy storage system, there will be a fixed infrastructure cost and the input energy charging cost, which is variable in nature, similar to the generating station. It is appropriate to apply the tariff principles of the generating station to maintain consistency in fixation and recovery of the tariff.

Proposal

6.5 It is proposed that the supplementary tariff consisting of supplementary storage charges (fixed) and supplementary energy charges (variable), on account of the installation of the energy storage system integrated with the generating station or the inter-state transmission system, as the case may be, shall be determined by the Commission separately based on the principle of servicing of cost and performance-based recovery of cost.

Capital Cost

6.6 The (Electricity Amendment) Rules, 2022 allow the installation of the integrated energy storage system with the generating station; however, no corresponding tariff framework was specified by the Commission. An introduction of a dedicated integrated energy storage system with the inter-state transmission system will facilitate resilience of the power system, reduce variability impacts and improve operational efficiency. It is also needed to ensure that only prudence-checked, reasonable expenditures are admissible in the tariff, with proper sharing of benefits and obligations. Moreover, enabling an integrated energy storage system as an alternative to immediate transmission expansion will potentially reduce system-wide costs.

6.7 The CERC (Terms and Conditions of Tariff) Regulations, 2024, provide the regulatory framework for the determination of supplementary tariffs for the emission control system, wherein the additional capitalisation on account of the emission control system has been recognised separately, considering substantial additional capital expenditure, the purpose of additional capitalisation and complementary to the generating station. The Commission has successfully implemented this mechanism. Similarly, in the case of the integrated energy storage system, the capital expenditure involved is substantial, and purpose is different but complementary to that of the generating station or the transmission system, which is meant to provide additional services to the same beneficiaries or the designated ISTS customers.

6.8 In view of the above, it is appropriate to consider the additional capitalisation of the integrated energy storage system separately, for the determination of

supplementary storage charges and supplementary energy charges, taking cue from the regulatory framework of the emission control system and the input price of the integrated mine.

6.9 To ensure transparency with the beneficiaries and to ensure the regulatory oversight, it is proposed that the generating companies intending to install an integrated energy storage system within an existing generating station must share their proposal with beneficiaries and seek approval from the Commission before undertaking the investment.

6.10 It is the obligation of the generating station or the transmission licensee to justify the proposal and hence, the Commission has proposed to regulate the requirement to be considered in the proposal, which includes essential parameters such as technological configuration, scope of work, project phasing, schedule, financing plan, IDC, foreign exchange requirement, tariff impact, and cost–benefit analysis.

6.11 To ensure that the proposal is viable and justifiable, the Commission has proposed to exercise strict regulatory oversight. Accordingly, it is proposed that the Commission will grant in-principle approval after assessing the proposal, including the reasonableness of cost estimates. However, for projects where the generating company has received viability gap funding, it is important for the Commission to consider the in-principle approval to ensure that the benefit of viability gap funding is passed on to consumers.

6.12 In case of the integrated energy storage system with the existing transmission systems, it is important to undertake consultations with the concerned stakeholders of the region under the aegis of the regional power committee. The consultation will be initiated by the transmission licensee by submitting the proposal to the regional power committee in advance, who will, in turn, disseminate it among the concerned representative members. The regional power committee will discuss the benefits of the proposed integrated energy storage system with the transmission system. A similar consultation process was followed when considering strengthening the interstate transmission system. Based on the discussion with the regional power

Committee, the concerned transmission licensee may approach the Commission for in-principle approval for assessing the benefits.

6.13 Notwithstanding the above, the transmission licensee has the liberty to deploy the integrated energy storage system for providing storage services as part of "other business", which will be governed by the CERC (Sharing of Revenue Derived from Utilisation of Transmission Assets for Other Business) Regulations, 2020.

6.14 To ensure that the proposed integrated energy storage system by the transmission licensee can be accommodated with the existing transmission system, it is proposed to lay down obligations of the Central Transmission Utility to check and submit its recommendations to the Commission after discussion in the concerned regional power committee. There may be a possibility that the integrated energy storage system will relieve the need for transmission augmentation or enhance transmission capability, and this must be clearly presented to the Commission by the Central Transmission Utility for its decision-making.

6.15 Further, to ensure that the proposed integrated energy storage system by the transmission licensee will be useful for the system operation, it is proposed to lay down obligations of the Regional Load Despatch Centre to check and submit its recommendations to the Commission after discussion in the concerned regional power committee. The Regional Load Despatch Centre may also suggest reserving a portion of the integrated energy storage system's capacity for the exclusive use in system operation.

Fixation of Supplementary Storage Charges

6.16 The supplementary storage charges will be determined from annual fixed charges worked out based on the separate capital cost of the integrated energy storage system discovered through the process of transparent competitive bidding. The components of the annual fixed charges of the integrated energy storage system will be the same as those of the generating station or the transmission system and its determination is proposed as under:-

a) Debt-Equity ratio of the capital cost of the integrated energy storage system will be as specified by the Commission in line with the generating station or interstate transmission system.

b) The methodology for the computation of depreciation will be the same as that followed for the generating station. There will be two scenarios for integrating an energy storage system: deployment in an existing generating station or in a new generating station. In the case of a new generating station, the depreciation stream of the integrated energy storage system will be separate, but will be computed from the date of commercial operation of the generating station. For an existing generating station, depreciation will be calculated from the date of operation of the integrated energy storage system. Depreciation is linked to useful life, which may differ across various types of energy storage systems.

c) The operation and maintenance expenses on account of integrated energy storage systems expenses have been proposed as 2% of the admitted capital expenditure (excluding IDC and IEDC) as on the date of commercial operation, which shall be escalated annually @ 5.25% during the first two years of operation which will be revised subsequently on receipt of adequate details of operational information of next 3 years.

d) The interest on working capital for an integrated energy storage system is proposed based on the working capital to be computed as receivables equivalent to 45 days of the supplementary tariff of an integrated energy storage system, maintenance spares @ 20% of operation and maintenance expenses and Operation and maintenance expenses for one month.

e) The return on equity is proposed as 14%. It may be noted that the rate of return on equity is proposed to be lower than the rates of return of the generating station and the transmission system due to the shorter construction period of the integrated storage system compared with the generating station or transmission system. However, the IRR of the integrating energy storage system is at par with the generating station or transmission system.

Operational norms of the Integrated Energy Storage System

6.17 The norms of operation for the integrated energy storage system are considered for the Normative Availability Factor, round-trip efficiency and Auxiliary energy consumption. The normative availability factor has been set at 90%, which is higher than the generating station's availability, whereas the round-trip efficiency has been set at 85%, and will be reviewed based on actual operational data. Auxiliary Energy Consumption of the integrated energy storage system is proposed as 5% of the input energy supply to an integrated energy storage system installed at the generating station or the transmission system. The operational norms have been proposed based on the literature surveys in the absence of specific operational data or OEM specifications. However, this will be reviewed once the operational data becomes available.

Recovery of storage charges of the Integrated energy storage system with the generating station

6.18 The recovery of supplementary storage charges of the integrated energy storage system installed in coal or lignite-based thermal generating stations is proposed to be recovered every month in line with the recovery of the capacity charges of the generating station. The recovery of the supplementary storage charges will be computed on an annual basis based on achieving the operational norms specified under these Regulations, and recovered monthly under a fixed storage charge. The supplementary storage charges will be allocated to the beneficiaries in proportion to the generating station's capacity at the location, where the integrated energy storage system is installed.

Recovery of storage charges of the Integrated energy storage system with the transmission system

6.19 Since the integrated energy storage system with the transmission system is considered as an element of the interstate transmission system, its recovery is also proposed in line with the recovery of transmission charges of the transmission element. It is proposed that the storage charges determined under these regulations in relation to the integrated energy storage system forming part of the transmission

system will be recovered in the same manner as the recovery of transmission elements is specified by the Commission.

6.20 In the existing regulatory framework, the transmission charges of each individual transmission element have been determined separately, pooled in the yearly transmission charges and apportioned to the designated ISTS customers through the Sharing Regulations specified by the Commission. It is proposed that the supplementary storage charges be apportioned to beneficiaries or long-term customers, or to the designated ISTS customers, in line with the transmission charges recovered under the Sharing Regulations.

Supplementary energy charges of the energy storage system integrated with the Generating Station

6.21 The supplementary energy charges of the energy storage system integrated with the generating station shall be calculated from the energy charges from where the un-requisitioned surplus power for charging the integrated energy storage system, and after accounting for round-trip Efficiency (RtE). The supplementary energy charges shall be determined based on the approved tariff of the source, the weighted average of the combination of sources used for charging, or as may be determined under the applicable regulatory framework specified by the Commission.

Supplementary energy charges for the energy storage system integrated with the interstate transmission system

6.22 The supplementary energy charges of the energy storage system integrated with an inter-state transmission system will be determined from the approved tariff of the input energy which comprises of supplementary fixed charges and supplementary energy charges both in case sourcing energy from the thermal generating station, approved tariff of renewable energy charges or the buying rate if it is purchased from market. If the supplementary energy storage system is used by external users, such users will pay the storage cost per unit (including fixed and energy charges) as may be determined as per the applicable regulatory framework specified by the Commission.

Incentive

6.23 The round-trip efficiency is proposed as 85% for the integrated energy storage system. If the generating company achieves a round-trip efficiency of more than 85%, the buyer will benefit from the extra energy. The buyer will generally get discharge during high demand, when spot market energy prices are also high. Thus, in order to encourage the integrated energy storage system to achieve higher round-trip efficiency, incentives are proposed. The existing regulatory framework allows the sharing of gains for achieving higher operational norms. Considering this, achieving higher round-trip efficiency needs to be shared with the beneficiaries and the generating company. In view of this, it is proposed that the normative rate of incentive @ 25 paise/kWh may be recovered by the generating companies for excess discharge of energy over and above the energy corresponding to the normative round-trip efficiency achieved on a cumulative basis. In the case of the transmission system, the transmission licensee will provide the storage services without owning the energy; such an incentive is dispensed with. However, the sharing of gains is proposed for the use of the storage energy for ancillary service or reliability purposes by the transmission licensee.

6.24 Accordingly, amendments have been proposed in Regulations 8, 9 (3a), 9(4a), 10(1), 10(1) explanation, 11(1), 11(2), 13, 14, 15, 16,18, 23, 29A, 29B, 30(4), 32, 33 (13), 34(1)(e) & 36(4),57, 61A, 64A, and 64B, 70 (FF), 74,78 and formula for recovery of transmission charges specified in Appendix-IV of the Tariff Regulations, 2024.

---

7. Proposal IV: Scheduling and Dispatch mechanism for the integrated energy storage system operated with the coal-based thermal generating station or interstate transmission system, as the case may be.

Issue

7.1 Availability of an integrated energy storage system with the generating station or the transmission system, as the case may be, and requisition by beneficiary, needs to be recognized separately.

Analysis

7.2 Chapter 7 of the Grid Code provides the methodology for scheduling and dispatching code. The existing regulatory framework addresses the scheduling of the electricity between the generating station and the distribution licensee or the bulk consumers.

7.3 The energy storage system is recognised in Regulation 45(11) of the Grid Code regarding the Scheduling of WS seller and ESS by QCA, Regulation 45(14) of the Grid code allowing a generating station or ESS or a drawee entity to schedule injection or draw only up to its effective GNA quantum and T-GNA quantum, as applicable, in accordance with the GNA Regulations. There is a specific Regulation 46 of the Grid Code for scheduling during security-constrained unit commitment, Regulation 48 of the Grid Code for scheduling from an alternate source of power by a generating station and then Regulation 49 of the Grid Code procedure for scheduling and dispatch for inter-state transactions. It implies that the scheduling and dispatch mechanism already recognises the energy storage system.

Proposal

a) For an Integrated storage system with the Generating Station

7.4 The energy accounting mechanism, including the location of metering for energy recording, is to be finalised by the Regional Load Despatch Centre.

7.5 The scheduling and dispatch mechanism from the stored energy of the integrated energy storage system with the generating station will be as per the National Load Despatch Centre in consultation with Regional Load Despatch Centre, after consultations with stakeholders.

b) For an Integrated storage system with the interstate transmission system

7.6 The energy accounting mechanism, including the location of metering for energy recording, is to be finalised by the Regional Load Despatch Centre.

7.7 The scheduling and dispatch mechanism from the stored energy of the integrated energy storage system with the transmission system will be as per the procedure to be developed by the National Load Despatch Centre in consultation

with the Regional Load Despatch Centre and the Regional Power Committee, after consultations with stakeholders.

c) Connectivity and access to the interstate transmission system

7.8 The energy storage system installed at thermal generating stations or interstate transmission systems is expected to dispatch stored energy during peak hours or under system exigency requirements. Hence, the capacity of the energy storage system that can be dispatched during peak hours would be based on available margins in the transmission/ evacuation system of the thermal generating station.

7.9 Since the energy storage system is complementary to the generating station within the part of the generation project, the capacity of the Storage system to be installed may be governed by the margins available.

7.10 Accordingly, amendments have been proposed in Regulations 84A of the Tariff Regulations, 2024.

---

8. *Proposal V: Mechanism for utilisation of stored electricity in an integrated energy storage system through the open market or ancillary market.*

8.1 The generating company or the transmission licensee needs to ensure optimum utilisation of the integrated energy storage system. If the beneficiaries do not schedule injections into the energy storage system or draw from stored energy for a prolonged period, it may lead to suboptimal utilisation of the energy storage system.

Proposal

a) For an Integrated energy storage system with the Generating Station

8.2 In case the beneficiaries do not intend to utilise the energy storage system for storage of energy or draw the stored energy, the generating company can utilise the same in Ancillary Services or open market after intimation to the concerned beneficiaries.

8.3 The income received on utilisation as ancillary services shall be shared with the original beneficiary after adjusting the fixed charges of the integrated energy storage system and energy charges used for charging after adjusting for the round-trip efficiency.

b) For an Integrated energy storage system with the interstate transmission system

8.4 The stored energy of an integrated energy storage system integrated with the transmission system shall be deemed to be available for use by the National Load Despatch Centre, in accordance with the provisions of the Ancillary Services Regulations as may be amended from time to time. The procedure, in this regard, will be issued separately.

8.5 Where the energy storage system is used by the generating company or the distribution licensee, the sale to the ancillary market or open market will be at the instance of the user company, and the transmission licensee shall have no role in the sale or purchase of electricity as may be specified by the Commission.

c) Commercial arrangement between the parties

8.6 The generating company or the transmission licensee can set up the energy storage system in their existing generating station after intimation to the beneficiaries, and can obtain the in-principle approval from the Commission. Similarly, the transmission licensee can set up an energy storage system in the existing substation after consultation in the Regional Power Committee and obtaining in-principle approval. No separate supplementary agreement is required, except where the generating company is entering into a contract with separate terms and conditions.

8.7 The contracted capacity of the energy storage system will be part of the existing contracted capacity of the generating station. In the case of generating stations with more than one beneficiary, allocation of contracted capacity of energy storage will be in the same proportion as the entitlement of respective willing beneficiaries in the thermal generating station.

d) Operational and Commercial procedure

8.8 The operational and commercial procedure for scheduling, dispatch and commercial accounting of the integrated energy storage system will be finalised by the National Load Despatch Centre in consultation with the Regional Load Despatch Centre and Regional Power Committee, after stakeholders' consultation.

8.9 Accordingly, amendments have been proposed in Regulations 78(3) and 84A of the Tariff Regulations, 2024.

---

9. *Proposal VI: Bringing efficiency and discipline in borrowing by introducing a ceiling on the rate of interest on availing debt from a related party*

9.1 The existing regulatory framework permits the loan from any sources. The interest rates of scheduled commercial banks are regulated, whereas other sources, such as loans from non-banking financial institutions, related or parent companies, or directors' loans, are unregulated. Since the regulatory framework for the projects covered under Section 62 of the Act adequately addresses the large number of commercial risks, the rate of interest on the loan will ordinarily not be higher on account of the project's performance. The higher interest of the projects covered under Section 62 of the Act can be due to the overall company's performance, or the group of the company, or some other extraneous factors or inefficiency of some other projects, not attributed to the projects under consideration for tariff determination, may not be passed on to the consumers.

Analysis

9.2 The existing provisions of Regulation 32 of the Principal Regulations provide admissibility based on the weighted average rate of interest calculated based on the actual loan portfolio or allocated loan portfolio of the generating company or the transmission licensee in line with principles of Section 61 of the Act. This regulatory framework is silent on the issue of the computation of interest on a loan where the generating company or the transmission licensee has availed the loan from a related

company, parent company, or non-banking financial institutions. Similarly, loans availed from Non-Banking financial companies ("NBFCs") may differ from those of the scheduled commercial banks, except for the government-owned NBFCs, such as PFC or REC, on long-term loans and advances.

9.3 In terms of the existing provisions of Regulation 18 and Regulation 32 of the Tariff Regulations, the generating company or the transmission licensee are expected to avail long-term debt from financial institutions on a prudent basis. It has been observed that the Income Tax Act, 1956, allows a deduction of a maximum of 12% of the interest rate in cases where a partner has availed loans under a deed from other partners. Thus, the interest rate on the related party loan needs to be addressed.

Proposal

9.4 It is proposed that where the part or the entire loan is availed from a related party at a higher interest rate, the rate of interest will be reduced by restructuring the loan within a period of one year. Meanwhile, where the part of the loan is availed from a related party, the weighted average rate of interest may be calculated on the basis of the existing loan portfolio excluding the related party loan. If the entire loan is availed from a related party, the weighted rate of interest will be the lower of the actual rate and the 1-year SBI MCLR plus 180 basis points.

9.5 Accordingly, amendments have been proposed in Regulations 32(5) of the Tariff Regulations, 2024, in the draft notification issued by the Commission.

---

10. *Proposal VII: Streamlining the framework of O&M expenses related to ash transportation expenses, specific transmission system and new Hydroelectric Projects*

Issue

10.1 The norms of O&M expenses of transmission lines specified by the Commission, considering a large transmission system of different areas, do not represent the O&M expenses of the transmission system developed within the area of Bhakra Beas Nigam Board due to its specific terrain area and considerations.

10.2 The existing framework allows the recovery of ash transportation expense incurred every month to be recovered at the end of the tariff period, resulting in the unnecessary interest burden on the beneficiaries. Further, the purpose of ash supply must be clearly specified in line with the MOEFC notification. Clarity is required on the treatment of revenue generation from ash transportation and the conditions to be fulfilled for claiming such expenses.

10.3 The Commission has specified the regulatory framework for normative O&M for HEP commissioned during the tariff period, i.e. 3.5% and 5.0% of project cost, while allowing certain components like capital spares, insurance, security expenses, etc. to be billed separately. However, the new HEP proposed norms remained unchanged; the same needs to be reviewed to give effect to exclusions from the O&M expenses allowed separately.

Proposal

10.4 It is proposed that the O&M expenses of the specific transmission system of the Bhakra Beas Management Board may be allowed based on past year data on a case-by-case basis at the time of the determination of tariff.

10.5 It is proposed that ash supply by thermal generating stations towards the construction of road and flyover embankments, shoreline protection structures in coastal districts, dams, or filling of the mine void may be allowed to be recovered from the beneficiaries every month after adjustment of revenue generated subject to true up and fulfilling conditions of providing auditor certificate, award of fly ash transportation contract through transparent competitive bidding and surplus revenue after adjustment of ash transportation expenses will be treated as Non-tariff income.

10.6 It is proposed that the O&M expenses of the new hydro generating units commissioned during the year will be allowed as 3.0% and 4.5% for the 500 MW and 200 MW sets, respectively.

10.7 Accordingly, amendments have been proposed in Regulations 36(1)(6) third proviso, 36(2)(a) and 36(3)(a) fifth proviso of the Tariff Regulations, 2024.

11. *Proposal VIII: Strengthening the regulatory framework of the input price of coal and lignite for energy charges*

Issues & Proposal

11.1 Interim Input Price for Lignite Mine

Issue

11.1.1 Regulation 37 of the Tariff Regulations, 2024 allows the interim input price for the integrated coal mines, whereas the same was not extended to the lignite mines, as there was an existing pooled lignite price. The pooled lignite price may not be representative of upcoming or individual mines due to differences in commissioning dates and the costs associated with them.

Proposal

11.1.2 It is proposed that the generating company owning an integrated lignite mine may also be allowed to approach the Commission for an interim input price similar to that of the integrated coal mine. [Regulation 37 (3) first and second proviso]

11.2 Integrated mines under Coal Mines (Nationalisation) Act, 1973

Issue

11.2.1 The existing regulatory framework under the Tariff Regulations, 2024, recognises mines allocated under the Coal Mines (Special Provisions) Act, 2015, only with the understanding that all the previous allocation of mines were regularised under the new Coal Mines (Special Provisions) Act, 2015. However, it is noted that some of the old mines' allotments are recognised under the Coal Mines (Nationalisation) Act, 1973. It might make it difficult to interpret issues related to statutory permission for the generating company and limiting the scope of the regulatory framework of the input price.

Proposal

11.2.2 It is proposed that wherever the Coal Mines (Special Provisions) Act, 2015 specified in the existing regulatory framework, the same may also be recognised as the Coal Mines (Nationalisation) Act, 1973.

11.3 Clarification on Performance Incentive

Issue

11.3.1 The Commission had reduced the Annual Target Quantity (ATQ) from 100% of the Coal quantity prescribed under the mine plan to 85% to protect the under-recovery due to a shortfall in production; however, the input price of coal (per MT) has reduced for the production of more than 85% to pass on the benefit to the consumer. In the case of thermal power plants, a similar mechanism exists where the incentive is provided for generating electricity of more than 85%. Further, an industrial practice, i.e., in Coal India Ltd, follows a performance-based incentive, with a range of 10 - 40% of the base price for Coal Quantity greater than 90% of Annual Contracted Quantity (**ACQ**). The existing regulatory framework is silent about the incentive for production above the ATQ level.

Proposal

11.3.2 The principle of tariff determination followed by the Commission balances the interests of the consumer and investors. While the generating company is protected from operational risk, the benefits of higher efficiency should be passed on to consumers. Hence, it is proposed to clarify that no incentive will be provided for coal production above ATQ until the 100% quantity prescribed in the mine plan. For coal production beyond the 100% quantity mentioned in the mine plan, the savings in the benefit are proposed to be shared on an equitable basis between the generating company and the distribution companies.

11.3.3. Accordingly, new clause (4A) is proposed to be inserted in Regulation 39 of the Tariff Regulations, 2024.

11.4 Recognition of Board's approval for additional capital expenditure

Issue

11.4.1 The existing regulation under the Tariff Regulations, 2024, envisaged the additional capital expenditure only as specified in the Mining Plan. It is observed that recent guidelines issued on 31st January, 2025, by the Ministry of Coal vide F.No. CPAM-34011/28/2019-CPAM [E-343762] prescribing a framework for preparation and approval of mining plan allows the mining company to carry out minor changes with the company Board's approval, without needing a full revision from authorities for every change.

Proposal

11.4.2 It is proposed that the scope of additional capital expenditure, in case of an integrated mine, be expanded to include the expenditure with the Board's approval, in addition to the mine plan. Accordingly, amendments are proposed in Regulation No. 42(1)(a) and 42(2)(a) of the Tariff Regulations, 2024.

11.5 Recognition of Board's approval for additional capital expenditure

Issue

11.5.1 Unlike the generating station, it is observed that there will be certain expenditure for the procurement of mine land, preparation of mine plan, etc., before formal investment approval. The expenditure incurred before the investment approval has been recognised by the Commission; however, there is a need to clarify the treatment of IDC & IEDC.

Proposal

11.5.2 It is proposed to introduce the third clarificatory proviso in Regulation 41(3) that the expenditure incurred for development of an integrated mine, with the approval of the Board of the generating company before the issue of the Investment Approval, shall also form part of the capital cost, and IDC and IEDC shall be considered in the manner as specified under Regulation 21 of these Regulations.

11.6 Streamlining the Depreciation of Land

Issue

11.6.1 The existing regulatory framework recognises the depreciation of conditional freehold land and requires it to be returned. It is observed that the conditions attached and the requirement to surrender the land back to the State Government after reclamation are distinct. Though no alternate use of the land is permissible, the generating company undertakes land reclamation and hence, the value of the land may undergo a change, or an alternate use may be considered. In that case, the beneficiaries who have paid the land's depreciation are entitled to recover the cost of the land.

11.6.2 The existing provision allows the cost of freehold land, where the allotment is conditional and where land is required to be returned, to form part of the value base for depreciation, subject to a prudence check. However, the regulation did not specify the treatment of such land after the completion of the mine's operational life, nor did it address situations where the land is put to alternate use. It must be ensured that while generating companies are allowed to capitalise such land for depreciation purposes where prudently incurred, any residual value or gain arising from the land at the end of the mine's life accrues proportionately to the beneficiaries, who bear the depreciation cost during the operational period. Clarity is needed on the end-of-life treatment of land assets associated with integrated mines, especially in cases of return or alternate use. It is also needed to ensure that gains arising from the residual value of land- after depreciation has been allowed during the mine's operational period- are shared with beneficiaries..

Proposal

11.6.3 It is proposed to create a distinction between the conditional freehold land and the condition to return the land. Further, it is proposed to amend the existing clause to add the precautionary condition that the deemed cost of the land will be shared with the beneficiaries, if it is considered for alternate use.

11.6.4 Accordingly, proviso to Regulation 45(2)(ii) is proposed to be amended as per the draft Notification issued by the Commission.

11.7 Streamlining the framework for the recovery of input price

Issue

11.7.1 The Commission has specified the comparison of the input price with the alternate coal available at the generating station in place of the commensurate grade of coal of Coal India Limited. Similar changes were not carried out in Regulation 50(2) of the Tariff Regulations, 2024.

11.7.2 In case of an integrated mine of lignite, curtailment of the production due to power surrender by beneficiaries or force majeure events, the generating company needs to be protected for the unused lignite, given the fact that the lignite cannot be stored or transferred like coal.

Proposal

11.7.3 It is also proposed to introduce clause (3) to allow generating companies to recover the fixed components of annual extraction cost corresponding to the unutilised lignite, after adjusting for any lignite sold in the open market. The recovery shall be made on a case-by-case basis, thereby maintaining prudence checks while addressing genuine under-recovery from beneficiary-side scheduling decisions. The amendment aims to strengthen principles of cost neutrality and beneficiary protection while maintaining incentives for generating companies to procure land prudently.

11.7.4 It is proposed to amend clause (2) of Regulation 50 (Recovery of input charges) to allow generating companies to compute the comparative energy charge rate using the price of alternative coal, wherever applicable, in addition to the notified price of Coal India Ltd. for commensurate grade of coal.

11.8 Simplifying overburden and Gross calorific value adjustment

Issue

11.8.1 There are regulatory differences that arise due to the conflict seen in

implementing the new Regulations in view of the old Mine Developer and Operator ("MDO") contracts, especially in the case of GCV and Overburden adjustment. This often leads to complications because of a different approach to computation in the MDO contract executed prior to the regulatory framework.

11.8.2 The overburden and GCV adjustment has implications on the input price, and regulatory oversight cannot be dispensed with. It is envisaged that the MDO contract to be entered after the Tariff Regulations, 2024 came into effect will necessarily be aligned with regulations or can be more stringent. However, where such an MDO contract was entered before the notification of the regulatory framework, the overburden and GCV adjustment formulae, as given in the MDO contracts, may be recognised as input prices. This will ensure that already concluded contracts are not opened.

Proposal

11.8.3 It is proposed that overburden adjustment and GCV adjustment formulae agreed by the generating company in the existing contracts may be recognised to prevent the complexity in the event of a difference and reopening of the contract entered before the introduction of the regulatory framework. However, in future contracts, the generating company has the freedom to evolve more demanding OB adjustment arrangements and GCV adjustment treatments than those given in the regulations.

11.8.4 Accordingly, amendments have been proposed in Regulation No. 51(3)(a), 51(3)(b)(iii), 51(3)(b)(vi) and 52(2)(b), providing that the adjustment is now to be made according to the formulae given in both the Regulations, if the OB or GCV adjustment, as the case may be, is not already factored in the Mine Developer and Operator contract.

---

12. *Proposal IX: Eligibility framework for the Regulatory Sandbox*

Issue

12.1 Given the rapid evolution of technologies such as digital grid tools, advanced analytics, storage, automation, and flexible resources, there was a need for a provision to address challenges in evaluating and scaling solutions for long-term system benefits. At present, no institutional mechanism exists to undertake testing or research. There is also a gap in research, development and innovation in the power sector in India, which hinders support for energy security, system reliability, technological advancement and self-reliance. Thus, it needs to evolve an institutional framework that provides a controlled environment to pilot innovative technologies, operational practices or business models without immediately being subject to the full scope of regulatory obligations.

Analysis

12.2 Internationally, the institutional framework called Regulatory Sandbox exists to provide a controlled environment for experiments of the products or services that benefit a large number of stakeholders. There is no institutional framework for the Regulatory sandbox in India's power sector. Since the Central Electricity Regulatory Commission, as a sectoral regulator and electricity market regulator, is responsible for the development of the power sector, it has been decided that the development of a framework for a regulatory sandbox be initiated, either as proposed by the stakeholders or as advised by the Commission.

12.3 Since the tariff of the generating company and the transmission licensee is regulated by the Central Electricity Regulatory Commission, it will be difficult for the regulated entity to undertake such initiatives unless it is recognised in the regulatory framework.

Proposal

12.4 It is proposed to introduce the new Regulation 101A to create an enabling framework for generating companies, transmission licensees, and entities whose tariff or input price is determined under these Regulations to participate in Regulatory Sandbox programmes for research, development, and innovation in the power sector. The detailed operational framework and procedure will be developed by the Commission separately.

12.5 The proposed regulations allow generating companies, transmission licensees

and other entities whose tariff or input price is determined under these Regulations to undertake approved innovation and research projects under the Regulatory Sandbox for which the additional expenditure is decided to allow up to 0.5% of the annual fixed cost or ₹100 crore, whichever is lower.

12.6 Accordingly, amendments have been proposed to introduce new Regulation 101A in the Tariff Regulations, 2024

---

13. *Proposal X*: Additional Proposals

Issue

13.1 In Regulations 27 of the Tariff Regulations, 2024, additional capitalisation on account of Renovation and Modernisation to the transmission system was specified. It is observed that the specific renovation and modernisation of the transmission system are not reflected, and any expenditure involved, if any, towards its renovation can be accommodated in the additional capital expenditure. In view of this, a specific regulatory framework for renovation and modernisation over and above the additional capital expenditure framework may not be required. The transmission licensee can claim such expenditure under the additional capital expenditure clause.

13.2 In Regulation 30(3) of the Tariff Regulations, 2024, an additional rate of return on equity of 0.125% allowed for every incremental ramp rate of 0.50% per minute achieved over and above the ramp rate specified by the Central Electricity Authority, subject to the ceiling of an additional rate of return on equity of 1.00%. However, the enabling regulation that would allow the National Load Despatch Centre to issue procedures or guidelines for measurement of the ramp rate was not specified. A similar enabling clause was specified in the Tariff Regulations, 2019 and the procedures framed thereunder, but it cannot be extended to the Tariff Regulations, 2024, as both the regulations are distinct.

13.3 The methodology for the calculation of availability of the transmission system, as specified in Appendix IV, does not recognise Thyristor Controlled Series Reactors (TCSCs) or Fixed Series Reactors separately. The Commission has already

recognised the transmission charges of these devices separately. With the increase in the use of these devices in the system and to ensure proper transparency in the availability and utilisation of Thyristor Controlled Series Reactors (TCSCs) or Fixed Series Reactors, the need was felt to consider the calculation of the transmission availability of these devices separately.

13.4 In the existing Clause 65(7) of the Tariff Regulations, 2024, the recovery of additional cost due to a shortfall in energy charges of the Hydro generating station is allowed automatically following a self-regulatory approach. However, the recovery of additional cost is admissible to the extent of the reasons not attributable to the generating company. To protect the interests of distribution companies and consumers, regulatory oversight is needed.

Proposal

13.5 It is proposed that the applicability of additional capitalisation on account of Renovation and Modernisation to the transmission system, as specified in existing Regulation 27 of the Tariff Regulations, 2024, may be omitted as it can covered under the additional capital expenditure clause.

13.6 It is proposed that in para (iii) of the second proviso of Regulation 30(3) of the Tariff Regulations, 2024, a new sub-clause (c) may be added to enable the National Load Despatch Centre to issue suitable guidelines for measurement by considering the energy measurement at a suitable interval.

13.7 It is proposed to streamline the methodology for the calculation of availability of the transmission system by introducing availability calculation separately for Thyristor Controlled Series Reactors (TCSCs) or Fixed Series Reactors in the Appendix IV & V of the Tariff Regulations, 2024.

13.8 It is proposed to amend Regulations 65(7) of the Tariff Regulations, 2024, to enhance regulatory oversight on the pass-through of additional costs due to a shortfall in energy charges of the Hydro generating station, instead of automatic recovery.

13.9 Further, in line with the above proposals, the corresponding amendments to

the Tariff Filing Forms, as well as a few editorial changes, have been proposed as per the draft notifications published on 1st December, 2026.

14. Draft Amendment in the Regulatory Framework

14.1 The draft of Central Electricity Regulatory Commission (Terms and Conditions of Tariff) (Second Amendment) Regulations, 2025, was published on 1st December 2025, and comments/suggestions/objections, if any, have been invited from the stakeholders.

14.2 The proposed amendments in the regulatory framework seek to attain the objective of enhancing the grid stability and reliability of the power system and enhancing the flexibility of the thermal power generating unit through the integration of the integrated energy storage system with the generating station or the interstate transmission system. This proposal will strengthen the resilience of the Indian power grid to manage large-scale variations in the generation output from renewable resources.

***